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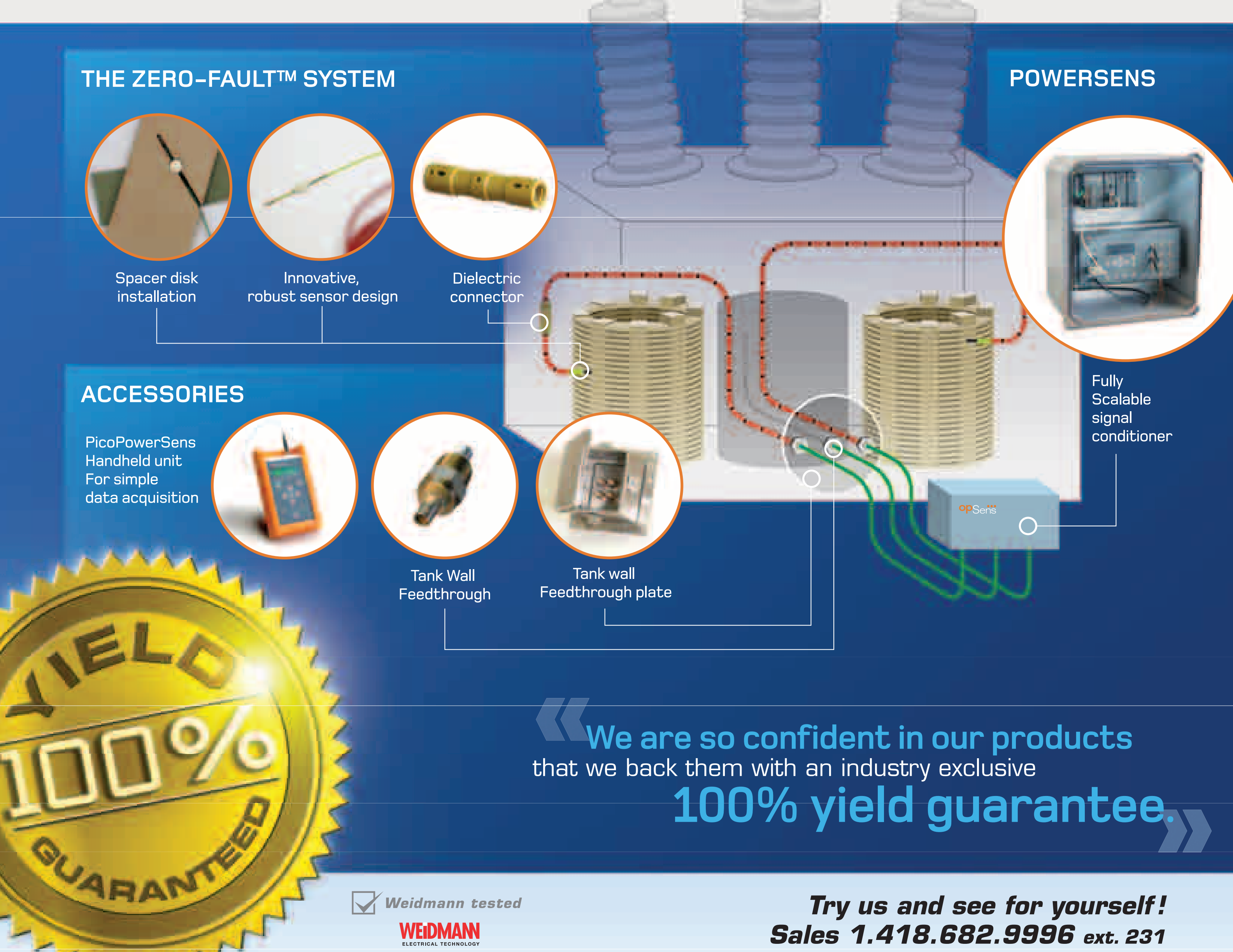

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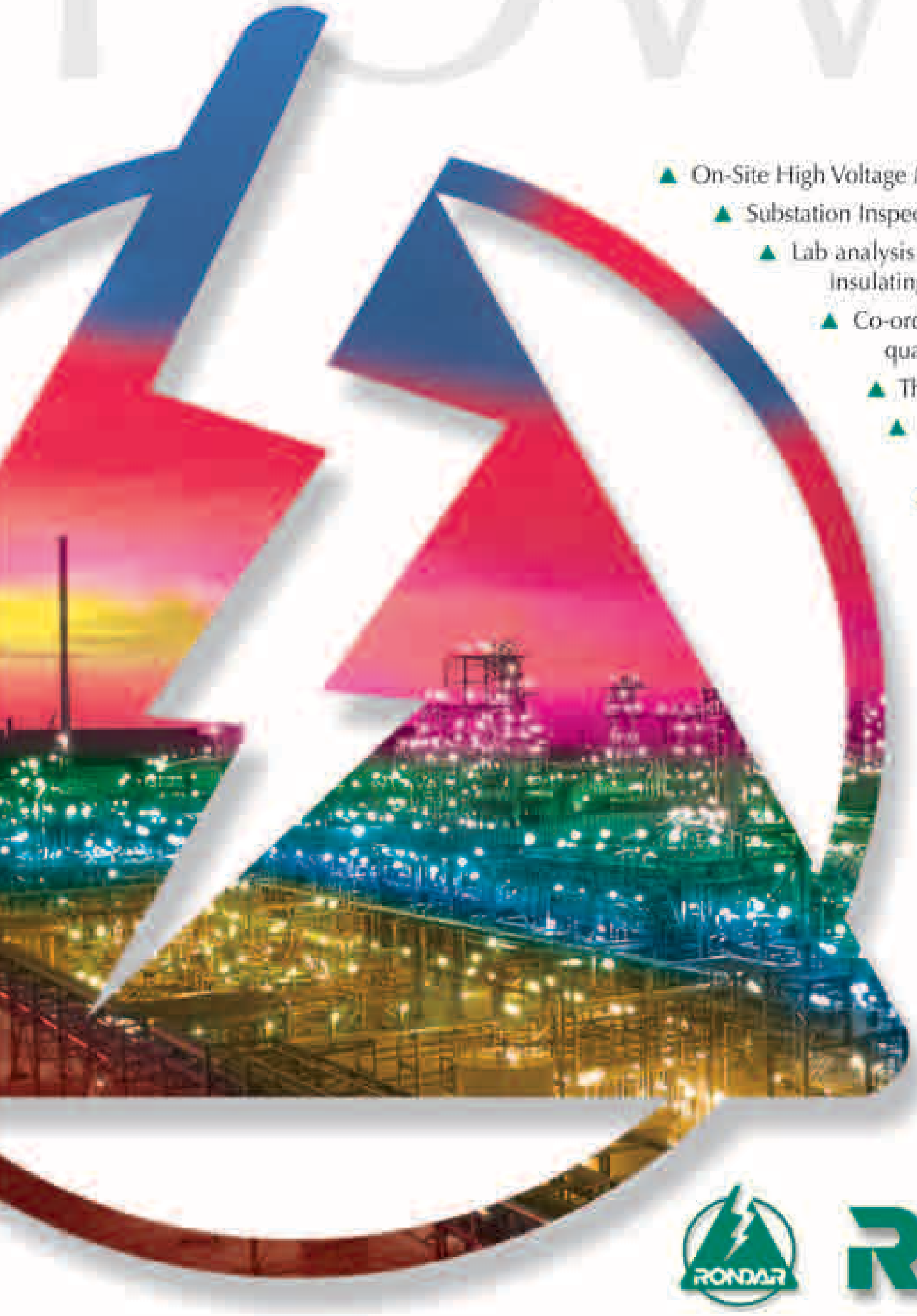

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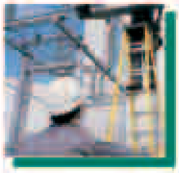

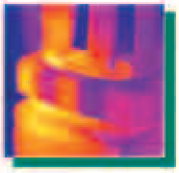

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POWER TRANSFORMER LIFE-CYCLE COST REDUCTION

Glenn Swift, Alpha Power Technologies; Tom Molinski, Manitoba Hydro

INTRODUCTION

A recent two-day seminar in Toronto entitled the Life Cycle Management of Power Transformers[1] typifies the current interest in determining the condition of power transformers in service, and in minimizing both the cost of keeping them in service and the risk involved.

One thrust of this effort has been to improve on-line gas-in-oil analysis[2]. Another is investigation of the effects of a variety of impurities other than dissolved gasses[3]. A Task Force has generated a report summarizing some of these approaches and other factors that lead to transformer failure[4].

An approach that relates loading to insulation degradation effects is the ANSI/IEEE Standard Guide for Loading Mineral-Oil-Immersed Power Transformers[5], that defines a relationship between winding temperature, sometimes called 'hot spot temperature', and rate-of-loss-of-life of a power transformer. While many would argue that the relationship is imperfectly defined[6],[7], it is nevertheless used by many utilitie, as an overloading guideline. In fact, the Standard was reviewed and revised slightly to include transformers above 100 MVA, in 1991[8].

As an indication of the validity of the hot spot temperature calculation equations of the Standard, a 1995 Canadian Electrical Association study [9] using fibre optic sensors concluded that "The thermal model provided in the literature (the Standard) for transformers with natural oil circulation is quite adequate to describe the thermal behavior of a transformer subjected to a variable load."

The equations are usually applied over a period of a few hours or a day, because of their complexity. Here, it is shown how to apply the equations in a rational way over much longer periods: years, or even decades. A year-long temperature variation model was developed to facilitate the calculations. It was then possible to track the lifetime of a transformer back into the past and/or forward into the future. This, combined with economic analysis, allows criteria to be developed regarding the best time at which to replace a power transformer due to load growth, i.e. to minimize the cost without significantly increasing the risk.

The transformer replacement analyses considered in this paper are for power transformers greater than 30 MVA on the Manitoba Hydro power system. These transformers typically provide connections between major system voltage levels or high capacity supplies to subtransmission systems. In the Manitoba Hydro system, the normal permissible loading levels of these transformers are 100% of their maximum name plate rating for either winter or summer peak. The permissible contingency loading levels are 125% of rating for winter peak and 100% for summer peak, assuming a summer ambient temperature lesser than or equal to 30°C and a winter ambient temperature lesser than or equal to 0°C. The basis of this is that during normal or emergency loadings, the loss of life of the transformer over a complete day must not exceed the normal daily loss of life as defined in the IEEE Standards[5],[8].

Figure 1 illustrates the fact that a high rate-of-loss-of-life for a short time is not a significant factor. Over the long term, it is the integrated rate-of-loss-of-life that is significant. Over the short term, it is the peak hot-spot (winding) temperature that matters, and whether or not it has caused undesirable contaminating products to form.

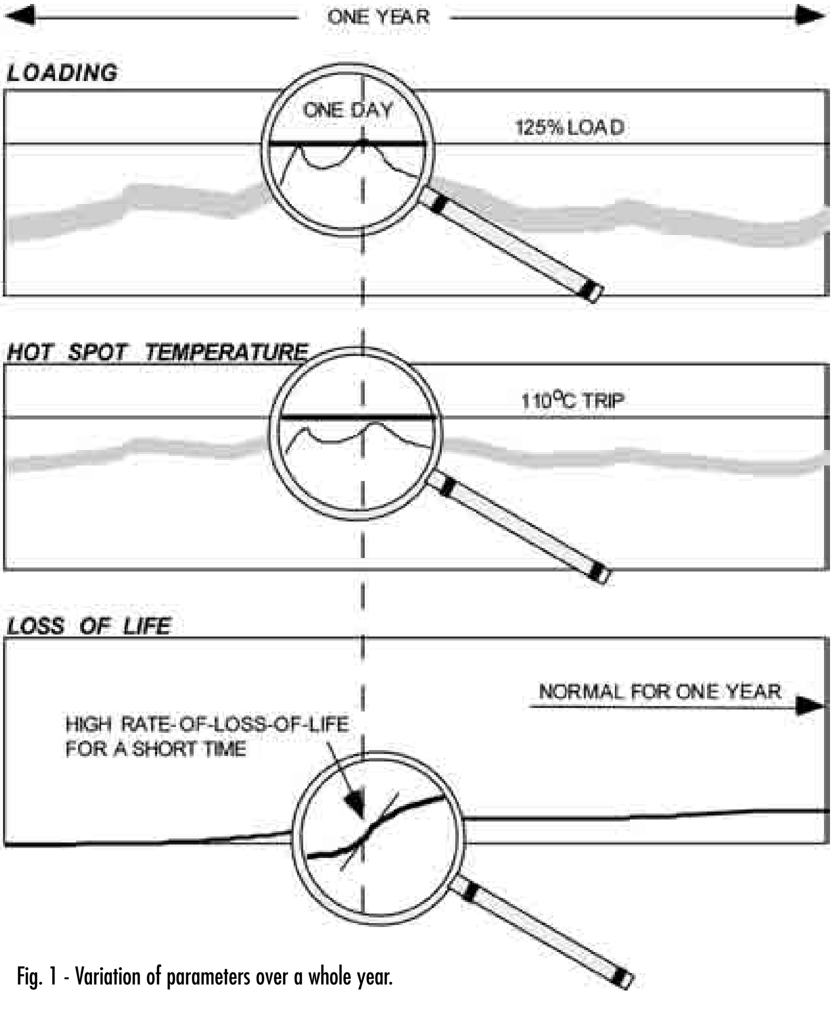

Fig. 1 - Variation of parameters over a whole year.

The recent trend for many utilities is to reduce capital spending, and one area that is being more closely scrutinized is capital expenditures on power transformers. Most utilities desire to make efficient use of the transformers without creating operating or maintenance problems. Load growth causes increased loading on transformers or necessitates the procurement of new transformers. Utilities may opt for increased transformer loadings, which could lead to other transformer problems that were undetected at the lower loading levels.

LOSS-OF-LIFE ANALYSIS

In order to use thermal loss-of-life equations (not given here because of lack of space: see Reference [8]), one must either know or assume a loading pattern and an ambient temperature pattern. There are both daily and yearly aspects to these as discussed below.

LOAD MODEL

The daily load variation for Manitoba Hydro and many other utilities has two common forms: a single hump shape and a double hump shape. A typical double hump shape is shown in Fig. 2. Historical data along with 'load shape' models based on the nature of known customer loads were used in this study.

The yearly load variation shown in Fig. 2 includes (for the case used in this study) a two-week outage of the transformer in parallel with the transformer being studied, at the time of the peak winter loading: a worst-case scenario.

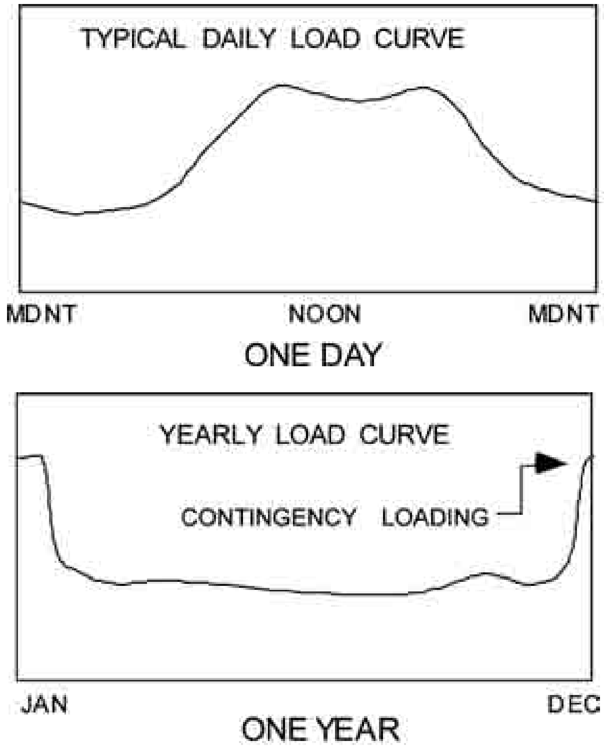

Fig. 2 - Daily and yearly load curves.

The last part of the load model is the load growth over the years. Load growth for each year into the future is estimated from known factors, for example planned industrial installations and geographically-related load patterns.

AMBIENT TEMPERATURE MODEL

Similar principles apply here, except that the variations throughout a day and throughout a year are based on long term averages published by Environment Canada[10]. Sinusoidal approximations are shown in Fig. 3.

Note that these have to be determined for particular regions. In Manitoba, there would be two such regions; one for Northern Manitoba and one for Southern Manitoba.

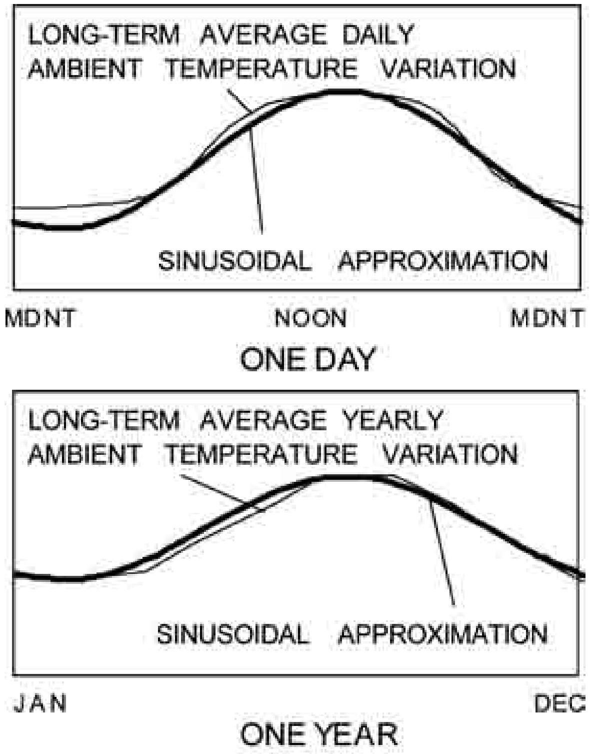

Fig. 3 - Daily and yearly ambient temperature approximations.

HOT SPOT TEMPERATURE AND LOSS OF LIFE

The winding hot spot temperature is usually the principal factor limiting the loadability of a power transformer. Higher winding hot spot temperatures cause degradation of the winding insulation material and can result in the formation of gas bubbles which facilitate the dielectric breakdown characteristic of the transformer oil.

Industry standards recommend that during rated load, the temperature of the winding hot spot should not exceed 110°C or 80°C rise above ambient (with the ambient daily average temperature of 30°C). These temperatures (24hr/day) result in what is defined as the normal loss of life for the power transformer, which works out to be 0.0369% per day [8].

The loss of life is related to the thermal degradation of the insulating paper. For paper insulation, the end of life is defined at the degradation point where the paper has lost half of its mechanical strength. The life of the paper insulation is then only 7.42 years at a continuous winding hot spot temperature of 110°C which increases to 50 years with a continuous winding hot spot temperature of 92°C.

For contingency overload conditions (few days), the industry recommendation is not to allow the winding hot spot temperature to exceed 140°C in order to limit the risk of releasing gas bubbles. However during certain emergency overload conditions, allowing a maximum winding hot spot temperature of 160°C, or even 180°C for a short duration (few hours) may be an acceptable risk for very infrequent occurrences.

Since all utilities do not have the same transformer loading criteria, the maximum allowable winding hot spot temperature limits tend to vary a great deal from utility to utility. This paper outlines a methodology to determine the maximum winding hot spot temperatures, so that transformer loading criteria can be safely rationalized taking into account that each utility can accept various levels of risk.

CASE STUDY RESULTS

To illustrate the argument, a real case has been studied: the Manitoba Hydro Minitonas Terminal Station Bank No. 4. Historical records and future load forecasts were used as data for the plot of peak load in Fig. 4.

Temperature variations throughout each year were assumed to follow “standard patterns” as described earlier.

From this data, peak hot spot temperature and accumulated loss of life were calculated using the equations of Reference [8]. These results are also shown in Fig. 4.

The present policy is that a transformer will be taken out of service and replaced with a larger unit when the peak load in this case (during winter when ambient temperature is less than or equal to zero degrees Celsius) exceeds 1.25 per unit. It can be seen that the peak load would have reached about 1.25 in 1996. In anticipation of this, replacement actually took place in 1995. (The removed transformer may be moved to another location, or sold.)

For periods into the future, the loading estimates are based on system load forecasts. Winding temperatures and loss-of-life are calculated in the same way.

The accumulated loss of life plot in Fig. 4 up to the replacement year (1995) is very low; less than 1%. From the peak winding temperature plot, notice that keeping the transformer in service another fifteen years, to the year 2011, would take the hot spot temperature to just about 150°C, the temperature at which it is sometimes assumed that gas bubbles may start to form in the oil. Correspondingly, the accumulated loss of life by the year 2011 is only 4.5%. It is only in the year 2020 that the accumulated loss of life reaches a full 100%.

ECONOMIC ANALYSIS

OVERVIEW

Reducing the life cycle costs of power transformers involves an evaluation of all present and future costs over the expected life of the transformer. Present value analysis is used to convert all future costs to equivalent present costs. The scenario with the lowest present value cost is the lowest life cycle cost of the power transformer. The procedure and formulas used in the present value economic analysis are not given here because of lack of space.

The premise of the engineering economic study was to utilize the present value method to examine the cost impacts (savings or debits) that will occur by delaying the scheduled replacement date of a new transformer, by allowing the existing transformer to remain in service after it has exceeded the existing Manitoba Hydro transformer replacement criteria. These studies were completed on a 50 MVA transformer that was replaced in the Manitoba Hydro system in 1995.

The scenarios involve delaying the replacement date of the replacement transformer itself from 1-16 years or from 1996-2011 (2011 is the planning horizon year for a 35 year economic study on a transformer initially purchased and installed in 1976). This is accomplished by estimating the cash flows for each scenario from 1995 to 2011. The net cash flows of all costs and residual (salvage) values are discounted for each year to bring them back to present values, which are in 1994 dollars in this study.

Note that the financial end of life (35 years in this study) is usually not the same as the technical end of life.

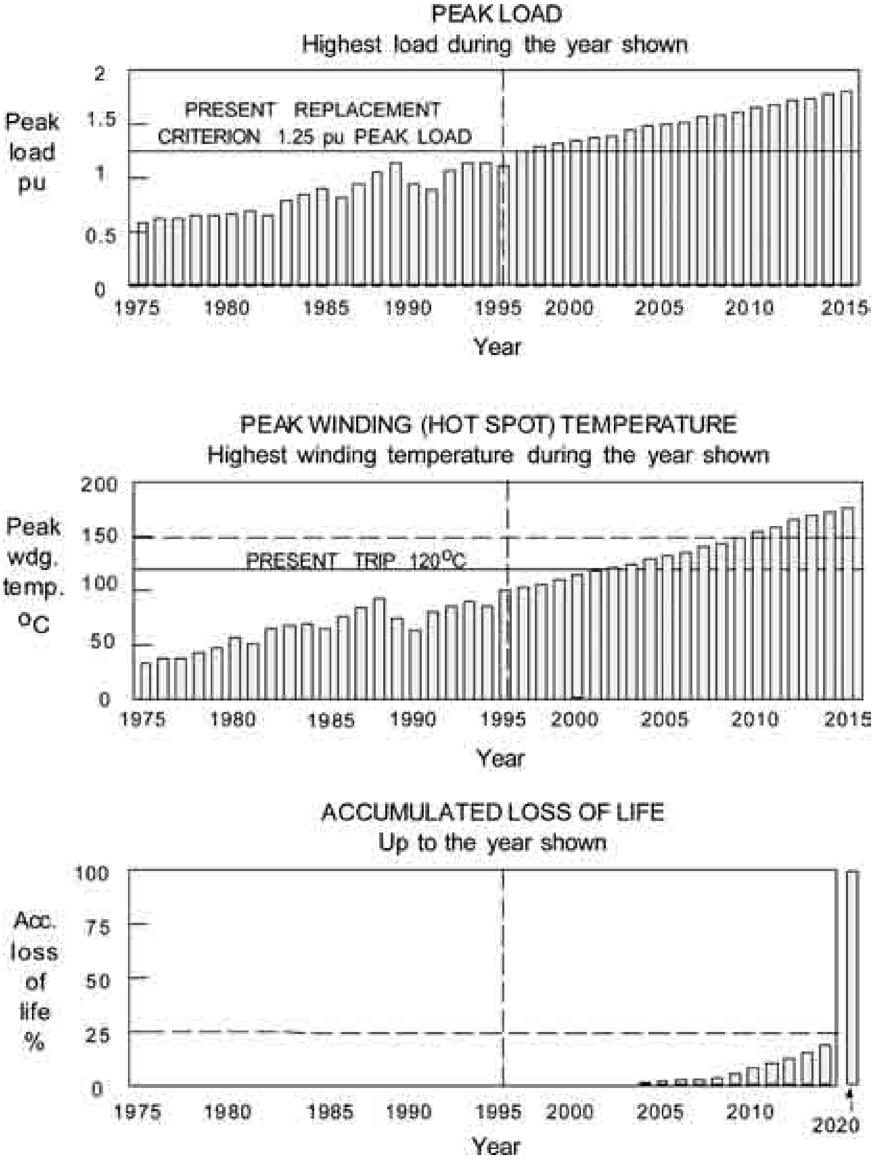

Fig. 4. Peak Load, Peak Hot Spot Temperature and Accumulated Loss of Life

The latter is the life over which the transformer will be permanently taken out of service (failed, not repairable, etc.) usually 35-50 years in Canadian utilities. The financial end of life is the life over which the transformer's residual value is depreciated to zero, and is usually less than the technical end of life.

ASSOCIATED COSTS

The engineering economic study included the following costs and residual values associated with the transformer replacement:

1. Purchase and installation (including Engineering) costs of a new (93.7 MVA) transformer in the year the replacement occurs.

2. Residual value of the existing (50 MVA) transformer in the year replacement occurs

3. Residual value of the new transformer at the end of the study horizon, 35 years from the replacement date of the existing transformer in (2) above.

4. Purchase and installation of a sophisticated on-line dissolved gas analyzer (DGA) and a sophisticated transformer protection and monitoring device (relay) in the first year of deferment of replacing the existing transformer.

5. Salvage value of the DGA and relay in (4) when the existing transformer is replaced by the new transformer identified in (1) above.

6. Costs associated with the increased load and no load losses as a result of retaining the existing transformer in service longer than originally planned.

It should be noted that operating and maintenance (O & M) costs for planned maintenance were assumed to be the same if either the existing or the new larger transformer were placed in service and were therefore not included as a factor in the analysis. The unplanned O & M costs (repairing oil leaks, etc.) are an infrequent occurrence (e.g. one in 20 years) and were also omitted in this analysis.

Failure costs are also assumed to be the same for either the existing or new transformer and were omitted. This is based on the fact that the statistical failure rate for power transformers (loaded lesser than or equal to 160% of rated) during the study period is the same for newer or older transformers as shown in Fig. 5. A detailed probability of failure analysis has been performed, confirming this statement, using the method of reference [11].

When compared with other factors such as transformer loss of life analysis, winding hot spot operating temperatures, risk, and other vital non-monetary factors, the net present value will furnish the utility with the knowledge required to identify the least-cost scenario.

It has been determined by others that failure costs can become increasingly important at load levels above 160% of nameplate rating[11]. However for the most part our studies are at load levels below 160% of nameplate.

ASSOCIATED SENSITIVITIES

It is recognized that there is an uncertainty regarding future interest, escalation and load growth factors. This study utilized load growth, interest, and escalation rates forecasted by the Manitoba Hydro corporate experts.

More present value studies will be completed to study the sensitivity of the cost savings due to various load growth factors, interest and escalation rates, over different economic study periods of 35, 40 and 45 years.

Various methods of calculating depreciation are possible. The sinking fund method was used here, because it most accurately reflects the true market value of the transformer being replaced.

The residual values of the existing and replacement transformers, and the relay and dissolved gas analysis equipment are all taken into account.

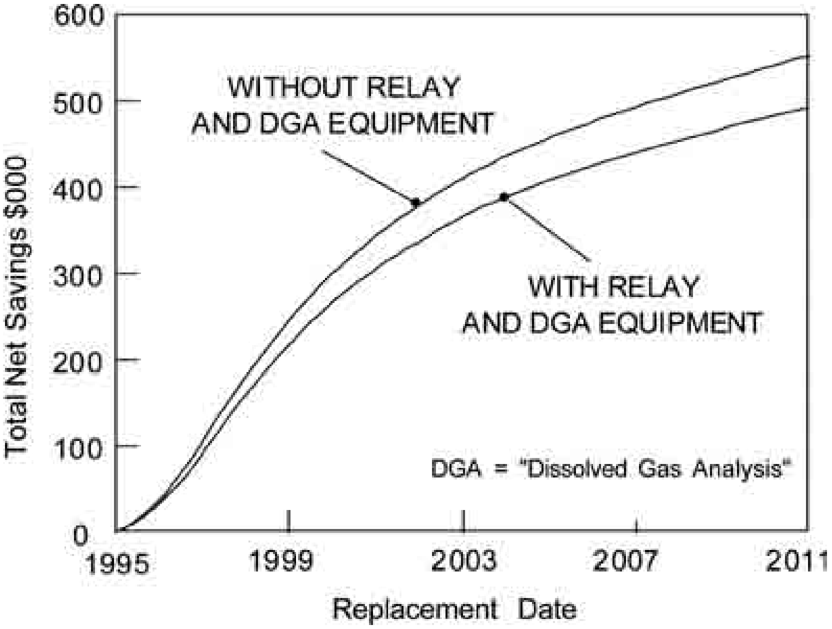

Fig. 6 - Total net savings in 1994 present value dollars

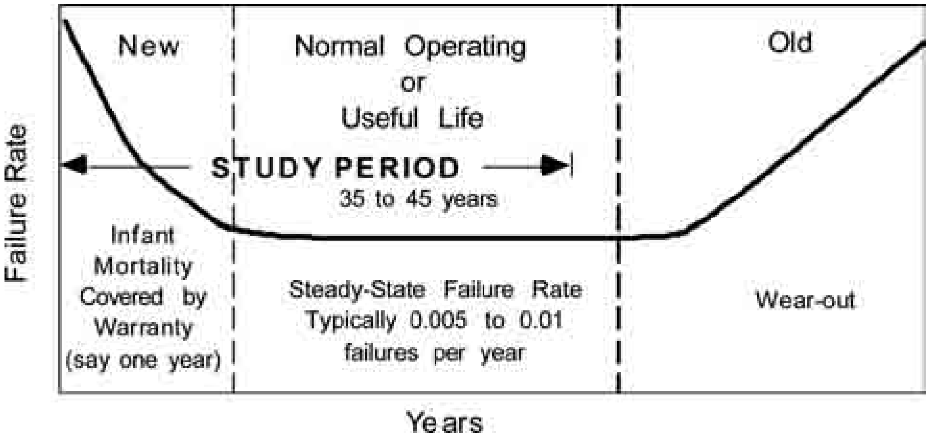

Fig. 5 - Typical failure rate curve.

RESULTS OF ECONOMIC ANALYSIS

As anticipated, the results of the present value economic study indicated that significant savings could have been realized by delaying the 1995 replacement date of the new transformer by several years.

The results from the 35 year economic study are shown in Fig. 6, where the curves represent the anticipated total net savings by delaying the replacement date of the new transformer from 1 to 16 years. In general, the longer the replacement date delay, the greater the savings. The savings occurring in year 2011 are $490,000 in 1994 present value dollars, even when the cost of a sophisticated monitoring relay and dissolved gas analysis equipment are taken into account.

Although it may not be prudent to attempt to 'significantly and safely' overload a power transformer without the relay and dissolved gas analysis (DGA) devices attached, an option to consider is to allow 'moderate' load increases say from 125% to 135% and not include these monitoring devices to save costs. The dashed line in Fig. 6 shows the additional possible savings.

PROTECTION AND MONITORING SYSTEM

Even though this analysis indicates that transformers may technically be kept in service longer than is the present policy at Manitoba Hydro, it is not disputed that there is a very small increase in the likelihood of failure of the apparatus. It is therefore recommended that if the longer life policy is adopted, a more elaborate protection and monitoring scheme will be justified.

A highly recommended form of monitoring is on-line dissolved gas analysis, and several such devices are commercially available.

Another 'line of defense' is a new multi-function transformer protection and monitoring system that provides not only the usual protection functions (differential protection, etc.) but also continuous monitoring of potentially damaging conditions such as the aforementioned dissolved gas analysis records, high harmonic current content, through-fault current stress, top oil temperature, hot spot temperature, and rate and accumulated thermal loss of life conditions.

In the case studied here, the cost of these protection and monitoring devices is well below the anticipated transformer replacement cost savings, especially considering that such devices can probably be re-used.

CONCLUSIONS

This article demonstrates a methodology to quantitatively determine the savings that can be realized by keeping power transformers in service longer than is the present practice.

The final recommendation for the particular case studied here was to delay replacement by nine years. This was considered to be a judicious choice since the loss of life and hot spot temperature both start to increase exponentially and the 'savings' curve starts to flatten out.

It is shown that it is more economical to overload existing transformers and accept the penalty of increased loss of life, than to relieve the loading by installing larger or more transformers. It is recognized that such a new policy, if followed, will lead to a greater dependence on the short-term or emergency overload capabilities of existing transformers and might increase the use of mobile transformers in the event of an outage or failure.

Based on loss of life and probability of failure analyses, it was determined that the risk of failure due to overloading for loading up to 160% of rating, is very small.

Sophisticated on-line transformer monitoring and relay systems for dissolved gas analysis and other important transformer parameters can be used as an added information source to safely improve transformer loadability and instill confidence in a longer in-service life policy for large transformers. A second benefit is that these devices are capable of alarming to indicate that a potential problem is developing so that it can be dealt with before serious damage occurs.

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SEVERITY CRITERIA - HOW HOT IS TOO HOT?

Mikael Cronholm, Infrared Training Center, Stockholm, Sweden

Since it was first conceived in the early 1960s, infrared thermography has evolved into a widely used, virtually indispensable tool for condition based maintenance, particularly for electrical equipment. Although thermal imaging has been around for a while, there is still a lot of education to be done as far as applying the technology in the most effective way is concerned. One of the most controversial and difficult applications is that of severity assessment, the need to prioritize our findings in such a way that the most serious problems are dealt with first. As an instructor in infrared thermography, I often come across the questions: "How hot is too hot?", "How severe is a problem?", and "How should I report this in such a way that the subsequent actions are appropriate?" Ideally, a set of guidelines tells us what to do for a given problem if a certain temperature level or differential is reached would be created. Many thermographers ask for this - a clear cut, easy-to-use table that will give them all the answers. But this, of course, doesn't exist, as there are just too many variables and unique situations for one precise set of answers. This paper is however, intended as a discussion starting point in order to further pursue the understanding and methodology for severity assessment.

INTRODUCTION

Your company has become a true believer in predictive maintenance (PdM), and the corporate plan is to virtually eliminate all unexpected shutdowns by using an array of high tech tools to uncover possible problems before they cause major damage.

Your job, as the thermographer, is to use an infrared camera to find heat related problems in, for example, electrical equipment, and detect hot spots. But once you find them, you start wondering, how severe are the problems?

Let us first acknowledge the fact that no facility is ever completely free from anomalies, problems or faults, (whatever you wish to call them). That is a utopia that unfortunately cannot be reached. It is output and profit that counts, and a completely fault-free plant would be too costly, and virtually impossible to maintain. If every anomaly was repaired immediately, there would be so many shutdowns for repair that production would suffer and the maintenance cost would be unbearable.

So the task at hand can be defined as: keep the plant running in a profitable mode with as few interruptions as possible and at the lowest cost, while maintaining safe operation in terms of worker, property, and environmental safety.

So we have to work within the following limitations:

- We cannot shut down the plant anytime, at our own whim
- We do not have unlimited resources for repair (manpower, time, spare parts in stock, etc.)
- Emergency shutdown of plant (or parts of it) should not be done if it is not absolutely necessary

WHY WE MEASURE TEMPERATURE

In infrared thermography, we define two types of comparative thermography – qualitative and quantitative.(1) Qualitative is used to discover and locate anomalies. This is the primary task. Quantitative means measuring the actual temperature of what is being scanned. Why do we want to do that? Is it not enough to find the anomaly, fix it, and be done with the problem? Sometimes, yes it is. In those situations, we don't need to bother with temperature measurement. That is, by definition, outside of the scope of this paper and will not be discussed further. However, with the three restrictions listed above, temperature measurement becomes necessary to be able to decide how to deal with the problem once it is found. Is it an emergency? Is it even urgent? Can it wait until later? And this is where the thermographer becomes nervous, wondering how does he or she determine the severity of a problem correctly?

DO SEVERITY CRITERIA EXIST?

Yes, many organizations and individuals have published severity criteria with temperature limits. I will not dwell too long on this or give a lot of examples. But, if there are so many criteria available, why can't we use them? The answer is; limited applicability. If there was one set of universal criteria that would solve this problem once and for all, why would there be so many of them out there? We cannot expect to get the answer served up on a silver platter for a number of reasons.

HOW SEVERITY CRITERIA SHOULD WORK

We want to get the most critical problems dealt with first! The task, therefore, is to prioritize and determine which are the most critical, second most critical etc., and then we can create an action plan.

So the criteria must be viewed in two parts.

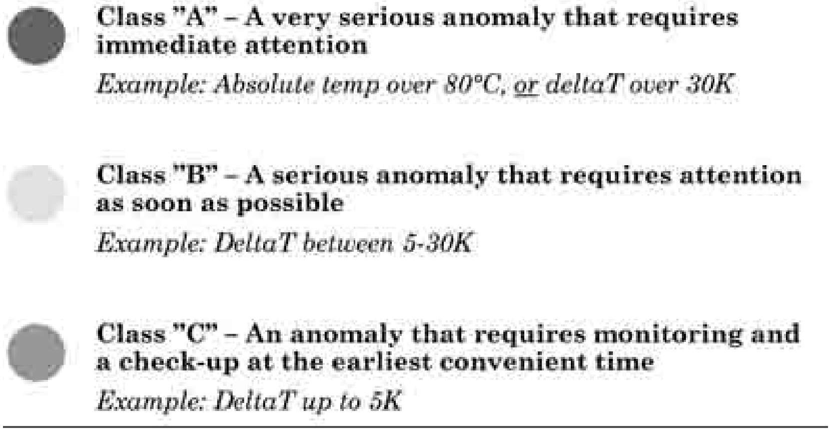
- Action definitions
- Temperature limits

ACTION DEFINITIONS

Action definitions will tell the reader of the report how the problem should be dealt with – a kind of predetermined plan of action that addresses every problem, according to its temperature. In the ITC Level 1 Course Manual(1) we present the following suggestion:

The bold text highlights the action definition and the italic text is the corresponding temperature limit.

A common misunderstanding is that "attention" means repair. Most action definitions that can be found (and they are many) will actually say "repair". So if it says "repair immediately" for the highest priority, it should mean that the equipment is immediately shut down and repaired. But, how often does that really happen? In reality, "immediate repair" seldom means that



● **Class "A" – A very serious anomaly that requires immediate attention**

Example: Absolute temp over 80°C, or deltaT over 30K

● **Class "B" – A serious anomaly that requires attention as soon as possible**

Example: DeltaT between 5-30K

● **Class "C" – An anomaly that requires monitoring and a check-up at the earliest convenient time**

Example: DeltaT up to 5K

Figure 1. Example of severity criteria

it will be repaired right now. Frequently, the issue does not even get addressed before it fails.

So, should a Class A issue be repaired immediately? Maybe not, as we are not at liberty to shut down the plant at will. In rare cases, however, we will ask for immediate shutdown. Any thermographer facing that situation knows how tenuous this decision is, as a shutdown may cost millions in lost production. If we order a shutdown, we must have the necessary reputation for not "crying wolf" in situations if it is later found that the fault was not as serious as proclaimed. And, once we shut down, do we have the spare parts and resources to repair at once? As we can see, there is a whole new set of complex questions that arise.

So we cannot realistically ask for immediate repair all the time, but we can always ask for immediate attention. What does that mean? It means that the proper people are alerted to the situation and start planning for a solution in the short and medium terms. The decision may, of course, be an immediate repair, but if it is not, some of the following actions may be decided:

- Lessen the load
- Apply additional cooling
- Order spare parts and labor
- Cordon off the immediate area for safety
- Schedule a time for shutdown and repair that will impact production the least
- Do additional measurements with other techniques for verification
- Schedule a trending of the problem to see how it develops

TEMPERATURE LIMITS

Criteria will always contain some kind of temperature limits.

Ideally, you find a problem and measure the temperature or temperature rise, or both. Then you consult the temperature limits table, which is part of the classification criteria in your thermography guidelines. Using the table in figure 1, referencing the italic text, if you find an anomaly with a temperature of over 80 degrees Celsius, it would be a serious anomaly that would receive immediate attention.

If we only have to consult the temperature limits, the determination becomes very easy. But, unfortunately, there are a number of things we have to take into consideration that makes the decision a lot more complex!

CRITERIA GUIDELINES AND TEMPERATURE LIMITS; WHERE THEY WORK AND WHERE THEY DON'T

Existing guidelines do work to some degree, but under limited conditions. Below is a discussion on where and why they do and don't work. As an example I am using the listings in NETA – Typical Guidelines used by Electrical Utilities 2), appendix 1.

A: Different types of components require different temperature limits.

This is a fact that is not often recognized, good thermographers do understand this though, and use their knowledge and experience to come up with reasonable conclusions. This fact however, does not help the beginner, nor does it serve to create consistency within a program where several thermographers work.

Our first example of this phenomenon is a bare metal connection in open air. Let us look at the two examples of temperature limits in the guidelines in NETA. In the first example, we should only look at the listing for "Overhead" components. The temperature limits seem fairly reasonable, and are quite close in the two examples listed.

The conclusion is that the guidelines seem to be developed for connections only, perhaps for historical reasons. Connections may have been the first type of problem that was dealt with, when thermal imaging was first used. It would result in reasonable action if the criteria were followed, as long as we are dealing with bare metal connections in open air.

We can still argue what the numbers should be, of course! But that is one of the points I am trying to make – guidelines should be individually developed for each operation. But we need a starting point, and for that, guidelines like those examples in NETA may serve a purpose as a starting base line. Notice that it says "typical"! Those numbers come from somewhere, from some utilities that have made a decision to use them, based on some kind of experience, or even just an educated guess.

The second case is a surge arrester or lightning arrester. Its purpose is to protect other components in a substation from high voltages coming in from the power line or inside the actual substation itself. Here is a simplified metaphor of how it may work, in normal operation and when it is faulty:

Figure 2. Upper lightning arrester rod on transformer bushing

Imagine a castle with a moat and a drawbridge. You want to allow entry to people who are walking through, but not to soldiers on horseback. So you design a spring-loaded trap door that will allow for pedestrians to pass but release for heavier loads, dropping them into the crocodile infested moat.

The simplest surge arrester is an air gap. Two pointed rods are directed towards one another on either side of an insulator.

An excessive voltage will have a chance to jump across the air gap and be grounded. This is the last defense against surges. It is a cheap insurance, but it is also not very accurate.

Another type looks like this. To the left is a complete unit and to the right a cut-away view showing the inside.

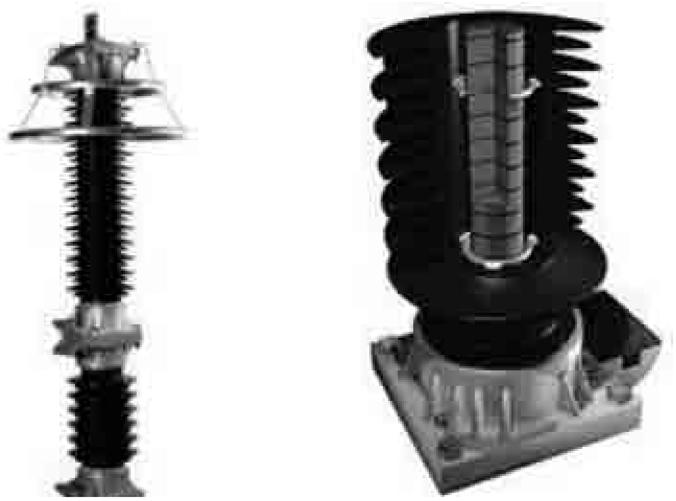


Figure 3. Typical MOV type surge arrester. Pictures credit: ABB

It is a device that has an almost endless resistance up to a certain voltage, after which it has almost no resistance – the trap door principle. There will be a very small leakage current going through it during normal operation. It contains a number of Metal Oxide Varistors (MOV's), usually made of Zinc Oxide. Each MOV element has a certain ability to keep voltages apart, and under normal conditions, when the line voltage is all that is present, they will cooperate in doing so. When a surge appears, it will ground it and thus protect the equipment on the other side from the surge. That is normal operation.

After it has been in service for a while it will have experienced a number of lightning strikes or excessive voltages which will have caused wear. This affects its ability to resist voltage, and some of the MOVs will start to conduct current even at normal line voltage. Below is an example of a failing arrester.

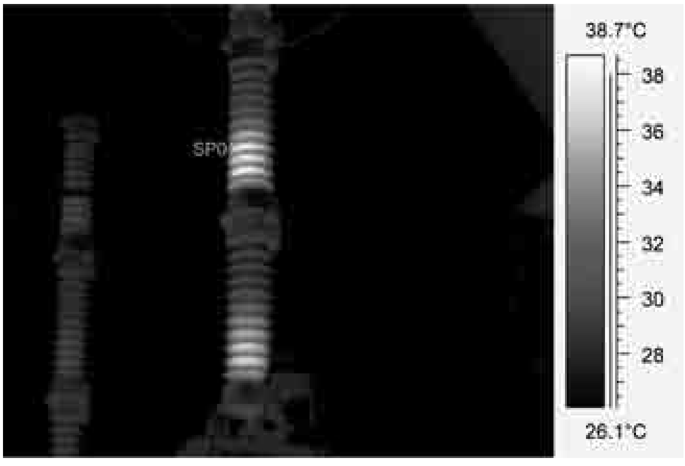


Figure 4. Thermogram of failing surge arrester

The question is: what is working and what is not? The cold parts will be the ones that no longer have their normal resistance, and will conduct current without heating up. The hotter areas are those that still resist current, and are therefore heated up. The leakage current will be higher. The danger now is that the arrester will need a much lower voltage to start conducting. The metaphorical trap door spring is weakened, and people start to risk falling down in the moat! To make the story short, the arrester will explode violently, spreading its debris around the substation, causing a line shutdown and risk of damage to equipment and injury to personnel. It is not a pretty sight. The one in the picture above actually did just that.

So, what about temperature limits? This arrester was working at an air temperature of 32 degrees Celsius, and it had a temperature rise on the hot area of about 7 degrees Celsius. Using the NETA temperature limits, this would not even qualify as a fault at all! Yet we know for a fact that this was very serious, since it exploded!

To summarize:

- Existing criteria are usually valid for terminations (connections) made of bare metal in open air, and should not be used for other components or parts.
- The next evolutionary step should be the development of criteria which are component specific.

B: Probability vs. consequence

This issue has been covered in a paper by Ron Lucier (3) and I recommend reading it, for a further discussion on this subject.

For the purpose of this paper, I will just illustrate with an example. The following problems are detected; both are on the same component type, namely a termination (or connection) of naked metal parts. (Remember, this is where we decided above that temperature limit criteria would work, at the present level of development.) One is on a disconnect switch (or isolator) and the other is on a transformer bushing. Temperature limit criteria alone will not decide the severity classification of these two problems. A faulty connection on the transformer will be considered serious because:

- It is expensive to replace
- It has long lead times for delivery of replacement equipment from suppliers
- It is often too expensive to keep on site as a spare
- It can cause severe secondary damage and put people in danger when it has catastrophic failures
- It causes long shutdowns when it fails
- It can often have internal faults that will be more difficult to find and judge

The disconnect switch is likely to fail in one of two modes. It will either weld itself together and become inoperable, or it will melt apart and open up like a fuse. The first case will not cause any power disruption per se. The second case will possibly cause an arcing condition until the relay protection switches the power off. None of that will cause any serious damage, unless people are too close in the second case.

The transformer bushing is potentially a more serious case. Chances are that a connection problem will not cause a failure with too much damage. But anytime a transformer is involved, the stakes are higher. (We may also have misjudged the problem, and it is in fact internal.) It can fail by itself, which is an explosive occurrence, or it can cause a secondary fire in the transformer which in the worst scenario will cause the whole transformer to go up in a big cloud of black smoke.

Another situation is when we have the same kind of equipment, but one is part of a more crucial process in the plant. A contactor is a contactor, but one may be switching a far more crucial line than the other, for the operation of the plant. To make such decisions, we would need a very good understanding of the individual plant and its operation. It is obvious that no standardized set of guidelines can be valid in such cases. It must be a part of the internal development of guidelines of each individual operator.

ESTABLISHING CRITERIA

Each organization needs to come up with it's own criteria – as part of the program guidelines – that will cover it's needs. This is, in fact, the way it seems to work in most cases, and that is why there are so many differing sets of guidelines.

The creation of such criteria should be a continuously evolving process that takes new experience into account. The plan should also be adapted to how the plant's reliability evolves. A problem that was not considered very severe before may be of key impact now as the facility's production operations have evolved.

If the temperature limits you are using give you so many "critical" problems that you don't have resources to deal with them "immediately", your plant is in such a poor condition that your temperature limits may have to be raised or you need additional resources. Otherwise, your resources will not be directed towards, nor keep up with, the most critical problems.

DEVELOPING CRITERIA AND GUIDELINES

Developing criteria and guidelines involves the accumulation of knowledge over the short and long term. Three tasks can be singled out in this process:

- Keeping up to date with what standards organizations and others publish
- Studying available literature about the materials and components we survey
- Documenting experience from the field that may be used to adjust criteria

Relevant standards organizations are IEC (International Electrotechnical Commission), NETA (InterNational Electrical Testing Association), IEEE (Institute of Electrical and Electronics Engineers, Inc.), NEMA (National Electrical Manufacturers Association), EPRI (Electric Power Research Institute), and of course ISO (International Organization for Standardization). (There may be others that I have not listed). Their websites are as follows:

www.netaworld.org
www.ieee.org
www.nema.org
www.epri.com
www.iso.org

For learning about materials and components, manufacturers are an excellent source.

Searching material specifications will prove valuable in developing criteria, especially when searching for the particular product or component does not give any result. Not only that, it is also an interesting learning experience.

If it is not electrical components but mechanical we are interested in, we can do a search for lubricating grease and see what we come up with. That should give us valuable input for determining severity of bearings etc that are heating up.

SUMMARY

In this paper, the following points have been presented:

- Existing, published severity criteria are insufficient
- Severity criteria must be individually developed for each type of component
- Severity criteria must be individually developed for each type of operation/company/industry

REFERENCES

1) ITC Level I Course Manual – Rev. 1.0 EN - Publ.no 1 560 093_D

2) NETA – Typical Guidelines used by Electrical Utilities (Appendix 1)

3) InfraMation Conference Proceedings, ITC 035 A 2002-08-01, "How to Guarantee Your Failure as an Infrared Thermographer", by Ronald Lucier

APPENDICES

Appendix 1: NETA – Typical Guidelines used by Electrical Utilities

Appendix 2: 3M 33 Vinyl Electrical Tape Data Sheet

CASE STUDIES REGARDING THE INTEGRATION OF MONITORING & DIAGNOSTIC EQUIPMENT ON AGING TRANSFORMERS WITH COMMUNICATIONS FOR SCADA AND MAINTENANCE

Byron Flynn, Application Engineer, GE Energy

I. ABSTRACT

Valuable information from Monitoring and Diagnostics (M&D) equipment installed on aging power transformers help utility personnel operate and maintain critical infrastructure.

M&D systems provide valuable on-line information from power transformers including gas in oil, internal hot spot temperature, insulation aging moisture content in winding insulation, bubbling temperature, and OLTC position tracking. This presentation reviews several methods of integrating M&D equipment to provide this information to SCADA and maintenance systems.

II. BACKGROUND

A discussion of Transformer Monitoring and Diagnostics has a basis on the fundamental construction of a transformer. The transformer is basically a machine consisting of several parts: This discussion, while seemingly overly simplistic, is useful to provide a basis of failure modes and monitoring and diagnostic methods.

The core and coil are the fundamental components of a transformer providing the coupling of magnetic flux between two windings. The core and coils are placed in a tank filled with oil and connected to bushings. The cooling system and control

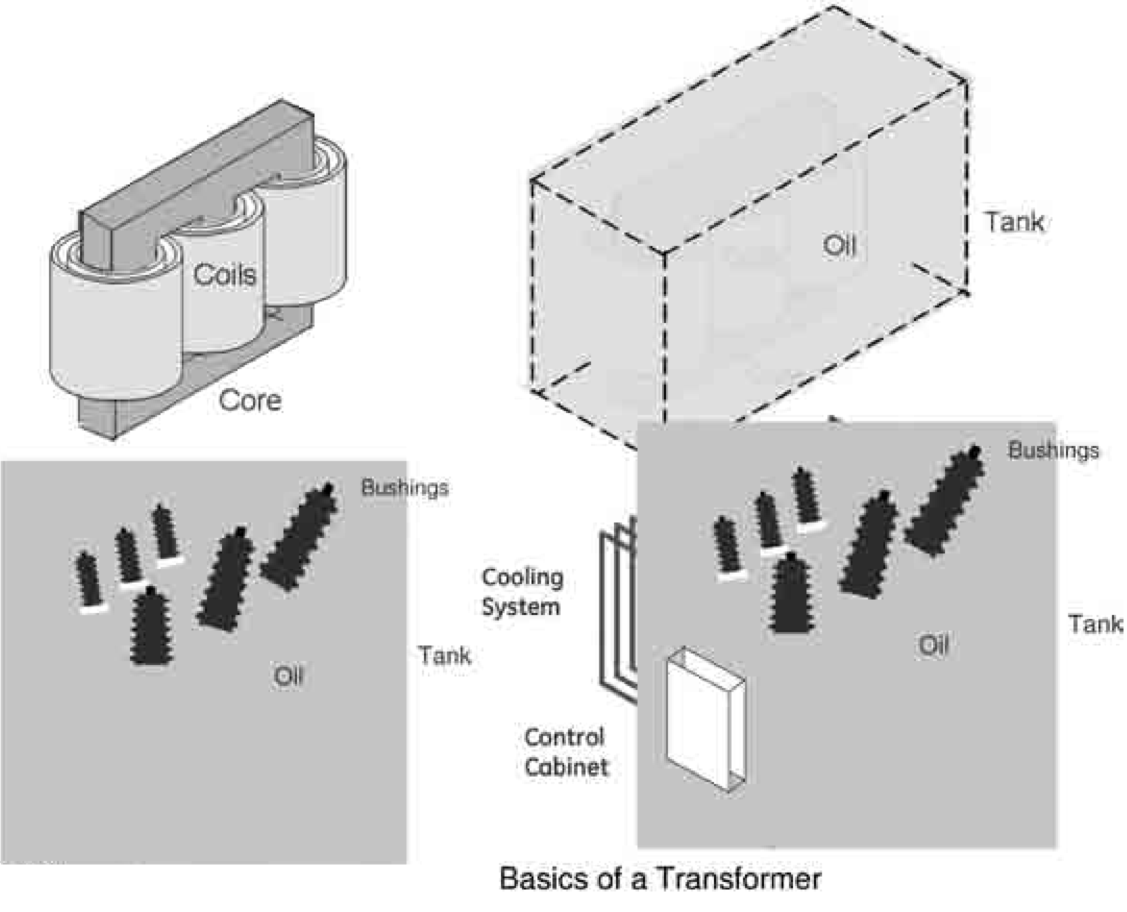


Figure 1

Basics of a Transformer

cabinet are the remaining fundamental components of a transformer. Additionally, many transformers in distribution substations include a Load Tap Changer (LTC) that provides additional voltage control on the distribution feeder.

There have been significant efforts to understand the various failure modes of power transformers. Applying the fundamentals of an FMEA analysis consisting of:

- Identify functions
- Identify failure modes
- Identify failure causes
- Identify effects of failure modes
- Identify criticality or risk
- Select on-line monitoring to match characteristic of developing failure cause(s)

The analysis of the failure modes of the various components then leads to a review of the inspection and maintenance procedures of power transformers. Then applying Reliability Center Maintenance (RCM) tools to the failure mode analysis information helps a utility design a monitoring system to optimize utilization and eventual life cycle.

Preventive and predictive maintenance:
Reduces the risk and costs of unexpected failure
Actual conditions drive maintenance and repair
Extending life of assets
Reducing costs of maintenance

On-Line diagnostic condition assessment addressing common failure modes:
Multiple sensors
Multiple on-line models
All parameters are recorded automatically and continuously Trend and limit alarms

ON-LINE DIAGNOSTICS MODELS

To deal with the potential overload of data, many utilities are installing systems with online diagnostics models. These models were installed to reduce the flood of raw data and to continuously provide information regarding the transformer health and operating history. Additionally, the Dynamic Loading Model provides a guide which can assist the dispatchers by calculating the overloading capabilities based on current operating conditisions, especially useful during critical times.

Additionally, early detection of problems, at the incipient stage, will help extend the life of the transformers. Detection of these problems is accomplished with several models which rely on various sensors installed on the transformer and in the substation, combined with other parameters manually entered. This data is then fed into industry standard and accepted models, which calculate the various outputs. These outputs are displayed and trended in the two Master Stations. These capabilities increase the useful data while significantly reducing the shear volume of data. The models focused on the main tank, the LTC and the cooling system and will be described briefly in this section. [1] & [2].

LOAD CURRENT MODEL

The first two models use routine calculations. The Load Current Model calculates average and maximum current on each winding based on one-second measurements.

This data is available for display and for trending in the Master Stations. The model's block diagram is shown below.

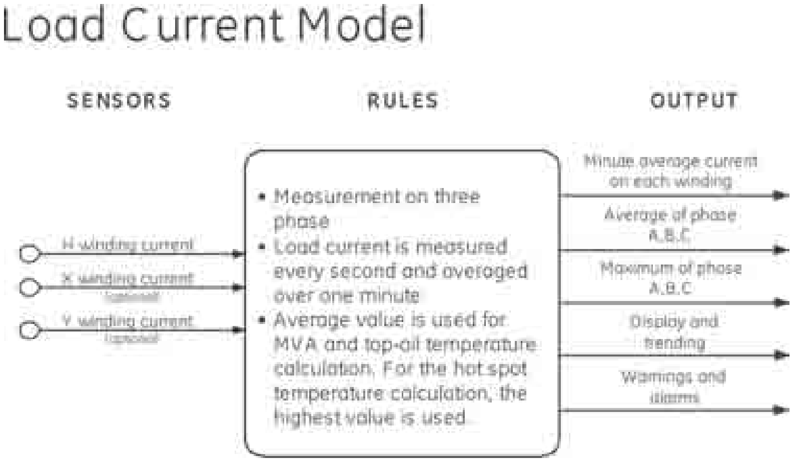

Load Current Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
• Measurement on three phase
• Load current is measured every second and averaged over one minute
• Average value is used for MVA and top-oil temperature calculation. For the hot spot temperature calculation, the highest value is used
Minute average current on each winding
Average of phase A,B,C
Maximum of phase A,B,C
Display and trending
Warnings and alarms

Figure #2: Load Current Model

APPARENT POWER MODEL

The Apparent Power Model simply calculates average apparent power (MVA) from the transformers' current and voltage. The average and maximum MVA readings are then displayed and trended. Warnings and alarms are also provided, if limits are reached.

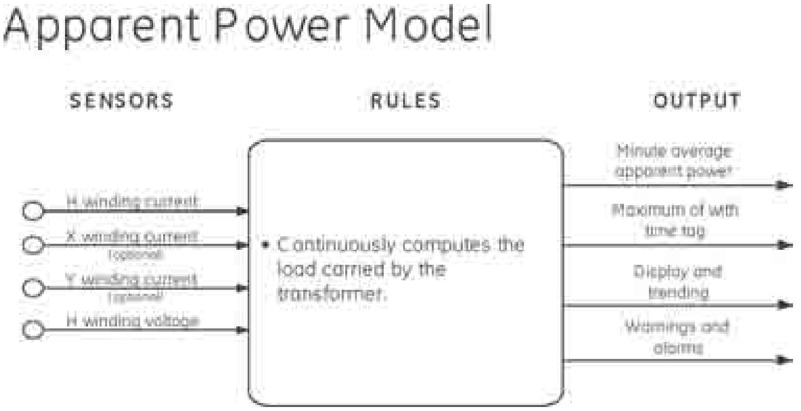

Apparent Power Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
H winding voltage
• Continuously computes the load carried by the transformer.
Minute average apparent power
Maximum of with time tag
Display and trending
Warnings and alarms

Figure #3: Apparent Power Model

WINDING TEMPERATURE MODEL

The Winding Temperature Model is based on IEEE and IEC loading guides. In accordance with these guides, it calculates the hottest spot temperature on each winding. The values are then made available for trend and display on the master stations. The following block diagram illustrates this model's inputs and outputs.

Computations are carried out according to:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers, Section 2.4, Equation 1
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for

Loading Mineral-Oil-Immersed Transformers, Section 7.2.6, Equation 16, 17, 18

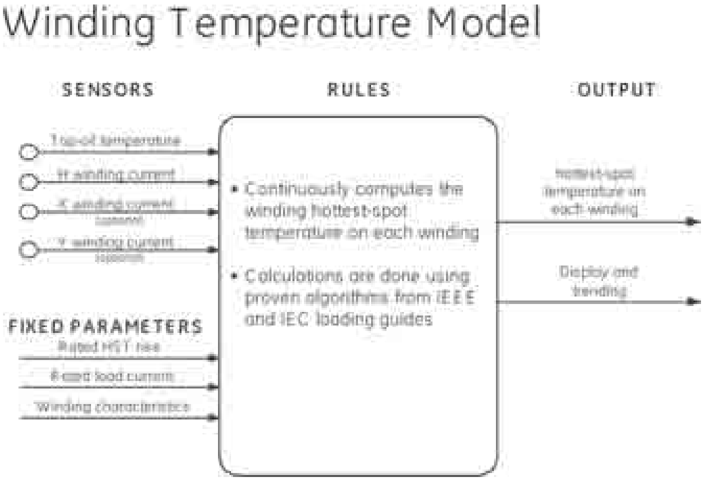

Winding Temperature Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
• Continuously computes the winding hottest-spot temperature on each winding
• Calculations are done using proven algorithms from IEEE and IEC loading guides
Hottest-spot temperature on each winding
Display and trending
FIXED PARAMETERS
Rated HST rise
Rated load current
Winding characteristics

Figure #4: Winding Temperature Model

INSULATION AGING MODEL

The Insulation Aging Model calculates transformer aging data based on two different methods, daily & cumulative (IEEE + IEC). The computations are carried out according to:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.6.2, Equation 7, 8
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 5.2, Equation 2 for 65°C thermally upgraded paper; Annex D, Equation D2 for 55°C normal Kraft paper.

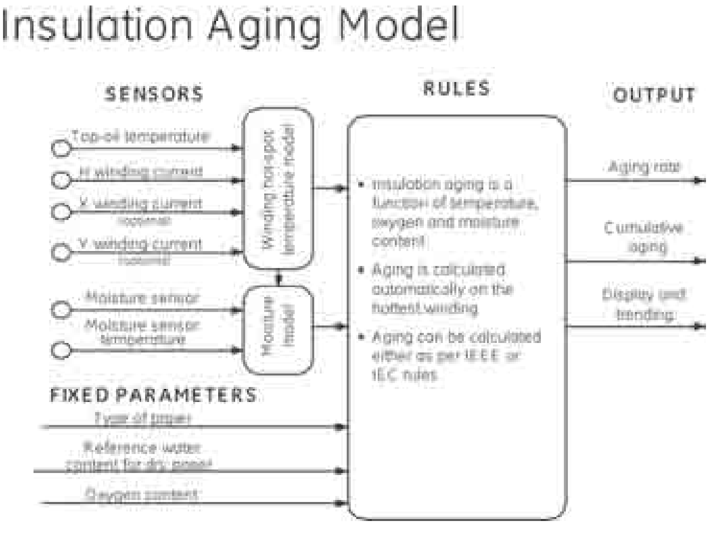

Insulation Aging Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Winding hot-spot temperature model
Moisture sensor
Moisture sensor temperature
Moisture model
• Insulation aging is a function of temperature, oxygen and moisture content
• Aging is calculated automatically on the hottest winding
• Aging can be calculated either as per IEEE or IEC rules
Aging rate
Cumulative aging
Display and trending
FIXED PARAMETERS
Type of paper
Reference water content for dry paper
Oxygen content

Figure #5: Insulation Aging Model

COOLING CONTROL MODEL

The system also can be used for cooling control using the model described in the block diagram below. The system is used as a backup.

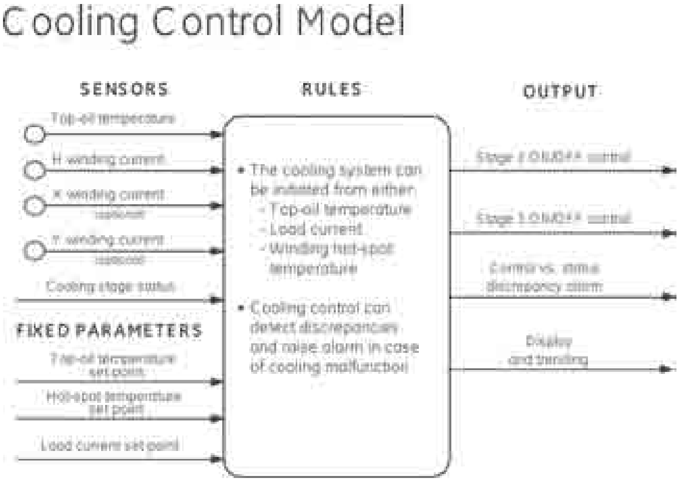

Cooling Control Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Cooling stage status
• The cooling system can be initiated from either:
- Top-oil temperature
- Load current
- Winding hot-spot temperature
• Cooling control can detect discrepancies and raise alarm in case of cooling malfunction
Stage 2 ONAF** control
Stage 1 ONAF** control
Control vs. status discrepancy alarm
Display and trending
FIXED PARAMETERS
Top-oil temperature set point
Hot-spot temperature set point
Load current set point

Figure #6: Cooling Control Model

COOLING EFFICIENCY

The Cooling Efficiency Model is used to determine if the Cooling system can lose efficiency over time due to fan failure, physical failure or coolers clogged with pollen, dirt, or nests. These conditions need to be detected before a transformer overload occurs. The model uses the following calculation methods:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.4.1, Equation 1
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 7.2.4, Equations 8, 9, 10, 11, 15

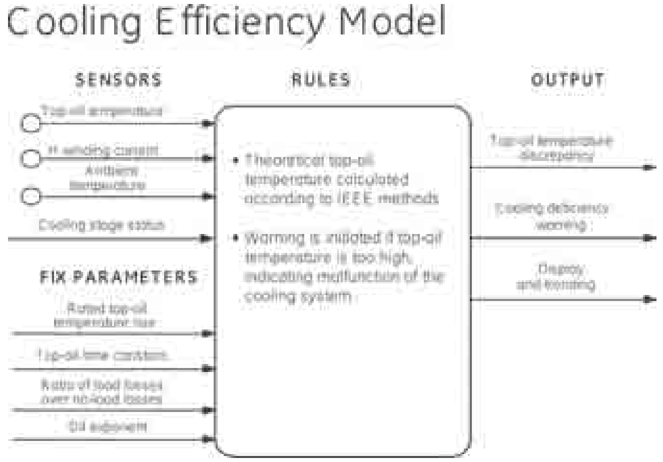

Cooling Efficiency Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
Ambient temperature
Cooling stage status
• Theoretical top-oil temperature calculated according to IEEE methods
• Warning is initiated if top-oil temperature is too high, indicating malfunction of the cooling system
Top-oil temperature discrepancy
Cooling deficiency warning
Display and trending
FIX PARAMETERS
Rated top-oil temperature rise
Top-oil time constant
Ratio of load losses over no-load losses
Oil exponent

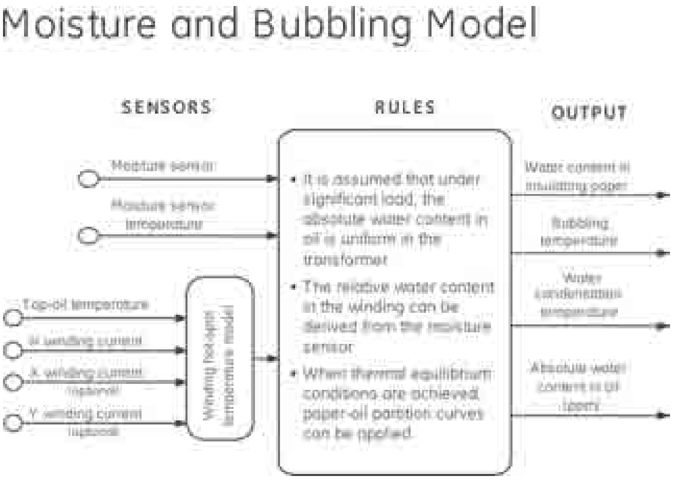
Figure #7: Cooling Efficiency Model

MOISTURE AND BUBBLING MODEL

Moisture content of paper is critical because it reduces dielectric strength and increases risk of bubbling at high load resulting in accelerates. The calculations are carried out in line with the following recommended methods:

- T.V. Oommen, "Moisture Equilibrium in Paper-Oil Insulation Systems", Proc. Electrical Insulation Conference, Chicago, October 1983

- W.J. McNutt, G.H. Kaufmann, A.P. Vitols and J.D. MacDonald, "Short-Time Failure Mode Considerations Associated With Power Transformer Overloading", IEEE Trans. PAS, Vol. PAS-99, No. 3, May/June 1980
- T.V. Oommen, E.M. Petrie and S.R. Lindgren, "Bubble Generation in Transformer Windings Under Overload Conditions", Doble Client Conference, Boston, 1995
- V.G. Davydov, O.M. Roizman and W.J. Bonwick, "Transformer Insulation Behavior During Overload", EPRIÒ Substation Equipment Diagnostic Conference V, New Orleans, February 1997

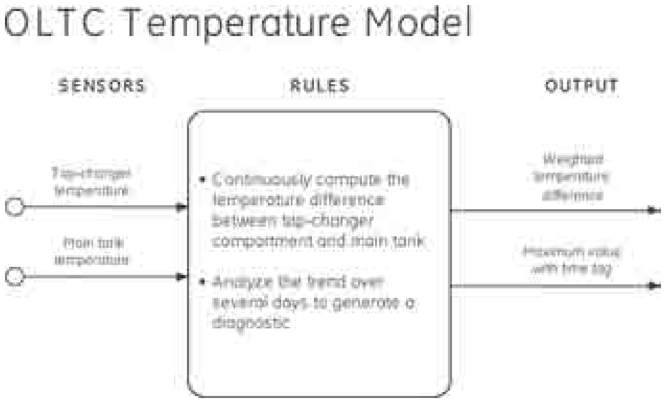

Moisture and Bubbling Model
SENSORS
RULES
OUTPUT
Moisture sensor
Moisture sensor temperature
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Winding hot-spot temperature model
Water content in insulating paper
Bubbling temperature
Water condensation temperature
Absolute water content in oil (ppm)

- It is assumed that under significant load, the absolute water content in oil is uniform in the transformer
- The relative water content in the winding can be derived from the moisture sensor
- When thermal equilibrium conditions are achieved, paper-oil partition curves can be applied.

Figure #8: Moisture and Bubbling Model

TAP CHANGER TEMPERATURE MODEL

Over the life of the transformer, the Tap Changer is a significant source of potential maintenance issues. Many problems with the tap-changer (contact coking) lead to temperature rise in the tap-changer compartment. This failure mode is easily detected by monitoring tap-changer temperature compared to main tank temperature.

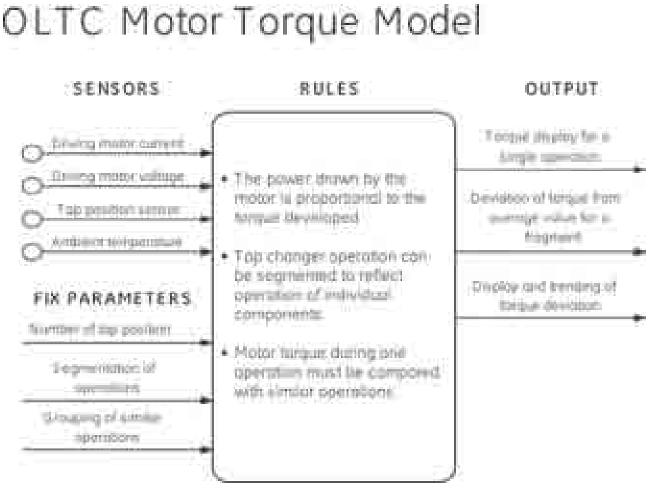


- Continuously compute the temperature difference between tap-changer compartment and main tank
- Analyze the trend over several days to generate a diagnostic

Figure #9: OLTC Temperature Model

TAP CHANGER MOTOR TORQUE MODEL

A change in the motor torque pattern is another indicator of mechanical failures of a tapchanger component. The Tap Changer Motor Torque Model provides a means of detecting a fault in the tap changer, the reversing selector, the gears or energy storage device.


OLTC Motor Torque Model
SENSORS
RULES
OUTPUT
Driving motor current
Driving motor voltage
Tap position sensor
Ambient temperature
FIX PARAMETERS
Number of tap position
Segmentation of operations
Grouping of similar operations
Torque display for a single operation
Deviation of torque from average value for a fragment
Display and trending of torque deviation

- The power drawn by the motor is proportional to the torque developed
- Tap changer operation can be segmented to reflect operation of individual components
- Motor torque during one operation must be compared with similar operations

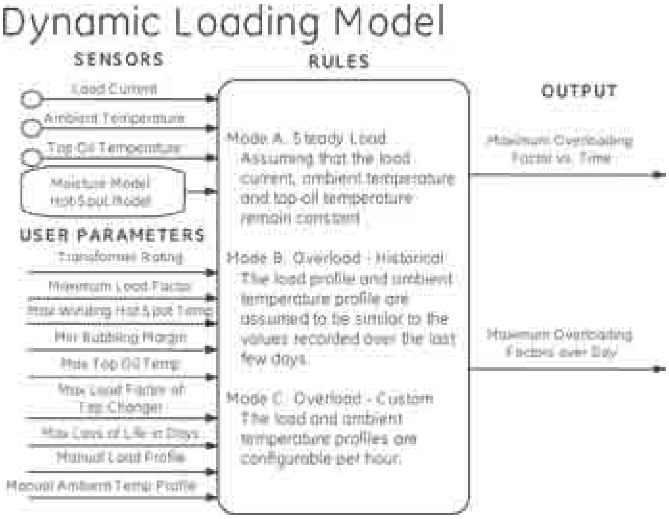
Figure #10: OLTC Motor Torque Model

DYNAMIC LOADING MODEL

The Dynamic Loading Model provides the operators with a perspective of the overloading capabilities, based on its current operating conditions. As the load grows in the area, this capability will become more critical in the operation of the transformer.

The Dynamic Loading Model is based on the following models:

- IEC 354, Section 2.4
- IEEE C57.91-1995, Section 5.2 & 7.2.6



Mode A. Steady Load
Assuming that the load current, ambient temperature and top-oil temperature remain constant

Mode B. Overload - Historical
The load profile and ambient temperature profile are assumed to be similar to the values recorded over the last few days.

Mode C. Overload - Custom
The load and ambient temperature profiles are configurable per hour.

Figure #11: Dynamic Loading Model

III. CASE STUDIES

CASE STUDY #1

Overall System Requirements

1. To gain remote control & monitoring of two Substations

- By reducing outage times
- By reducing operating costs
- By reducing trips to the field

- By catching problems before failures occur
- By maintaining a healthy system.

2. To improve monitoring and load management
   - By balancing single phase loads
   - By monitoring underground for potential overload conditions
   - By managing the transformer loading and
   - By monitoring and controlling the voltage levels
3. To accommodate future SCADA System growth and to be expandable throughout the entire electrical system
   - Including the remaining substations
   - Including other distribution breakers and capacitors

The overall system installed is shown in the architecture drawing in Figure #1. The two dispatch centers communicate with the SCADA system via DNP 3.0 over IP on the SCADA System. Data Concentrators/RTUs were installed in the substations, which communicated with several Intelligent Electrical Devices (IED's). Additionally, communications equipment was installed to support the initial system. The new communications equipment utilized available channel space on the company digital microwave system.

New Dispatch Centers

The SCADA software was configured nearly identically at the two masters. The only other difference with the two dispatch center systems is the master stations have different IP and DNP addresses. This allowed the two systems to be operated independently. System analog and status changes and control signals are communicated to both masters over the same communication line. This is possible because the system operates over Ethernet communications. This also provided the ability to dispatch for the entire system from either master, providing additional coverage during busy times or a secondary master station if a problem occurs. The similarity of the two Master Stations simplified software configuration of the masters and the RTUs. The communications system will be discussed in further detail in a subsequent section.

Integrated Transformer Monitoring

Two monitoring systems were installed on the two 120 MVA transformers and integrate into the system using DNP 3.0 protocol over IP. The monitoring and diagnostic (M&D) systems contain smart RTUs, which form the foundation for the diagnostic system.

These RTUs integrate data from several sensors and the transformer monitoring IEDs and perform the diagnostic models. These IEDs consist of a LTC monitor, and sensors which monitor combustible gases and moisture of the oil in the main tank. The M&D RTUs then analyze the data using several of the diagnostic models. It is important to operations and maintenance personnel that the transformer monitoring system reduce the amount of raw data provided. All the intelligent models described in the previous section were implanted which provided information regarding the health of the transformers. These models focused on three main areas; the main tank, the cooling system, and the Load Tap Changer (LTC).

CASE STUDY #2

This system utilizes on-line monitoring with no on-line diagnostics. It provides an inexpensive method to capture data from the transformer and assist in off-line diagnosis of transformer problems.

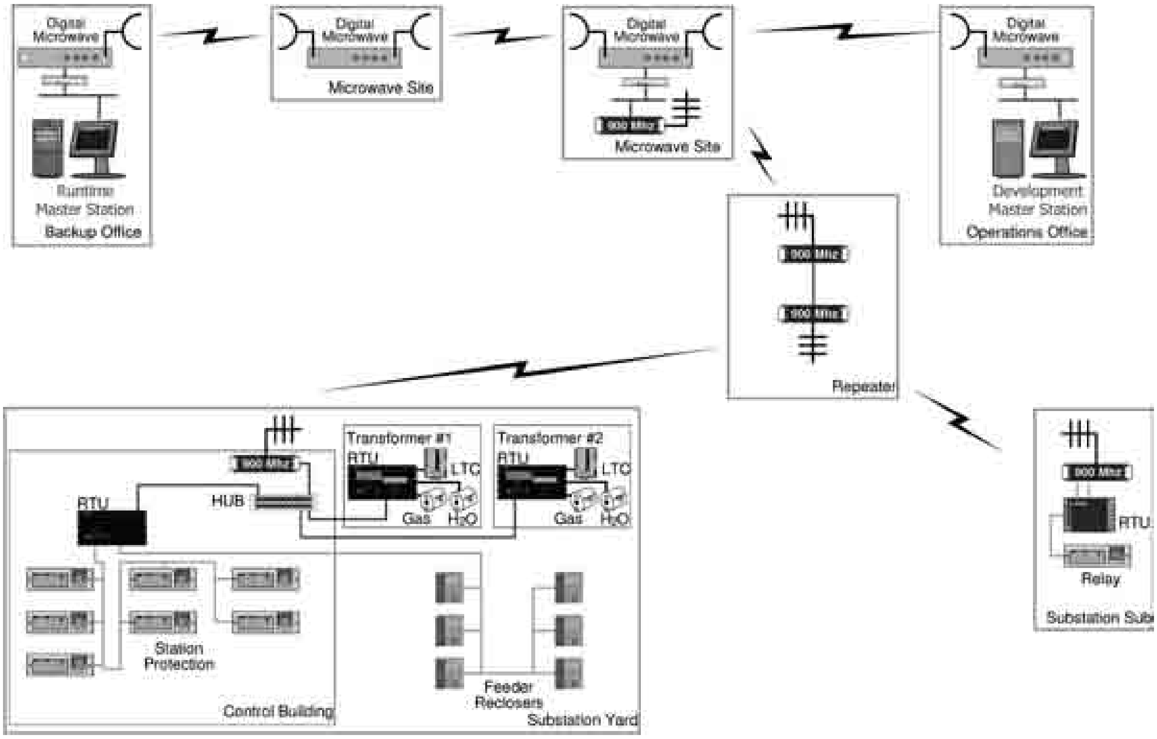


Figure #12: Case #1, System Architecture

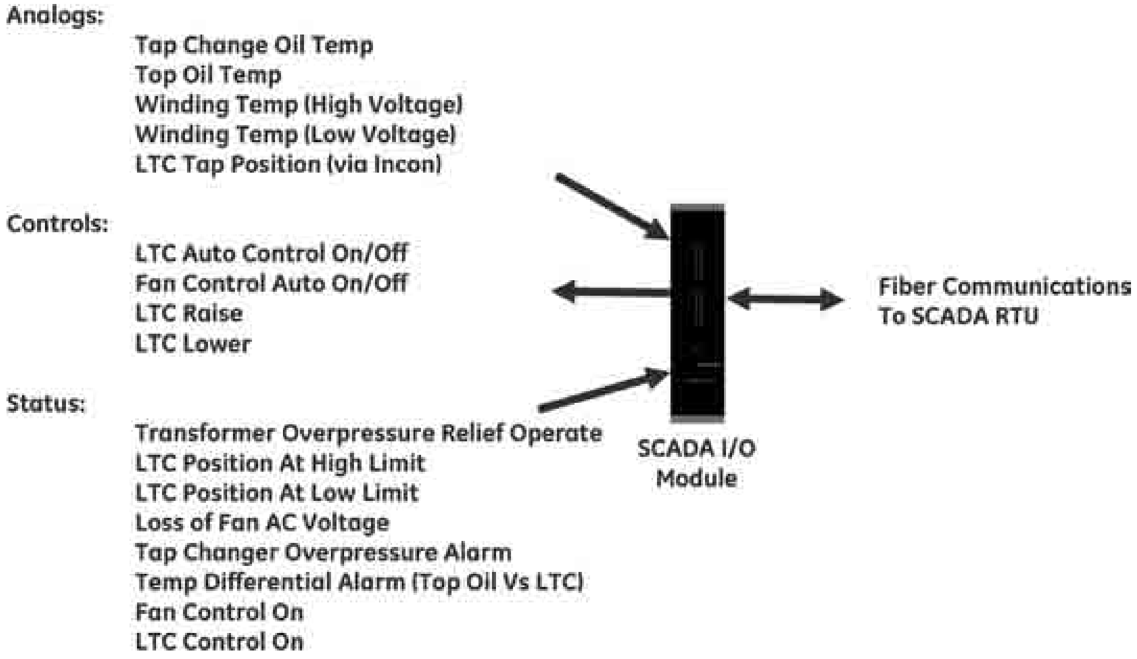

Analogs:
Tap Change Oil Temp
Top Oil Temp
Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position (via Incon)
Controls:
LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower
Status:
Transformer Overpressure Relief Operate
LTC Position At High Limit
LTC Position At Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On
SCADA I/O Module
Fiber Communications To SCADA RTU

Figure #13: Case #2, System Architecture

Distributed I/O

This system is based on distributed SCADA I/O modules communicating back to an RTU in the control building. The I/O modules have on board digital status, analog and control allowing the transformer monitoring system to be integrated into the SCADA system.

Analogs – the following values are used to detect problems with the LTC or the main tank. Additionally, indication of the LTC position is provided which can be used to determine operation of the LTC and potential problems such as LTC hunting or subsequent tracking of the number of operations of each tap between maintenance intervals. These values include:

Tap Change Oil Temperature – to detect problems with the LTC

Top Oil Temperature – can detect problems with the tank or cooling system

Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position

Controls – provides on/off control of the LTC and Fan automatic systems. In addition, remote control of the LTC is also provided. The points included are:

LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower

Status – The status points monitored include indication of the control points and on other transformer alarm points. The Top Oil vs. LTC temperature alarm is a primary alarm indication of LTC problems whenever the LTC tank temperature exceeds the top oil tank temperature. The status points include:

Transformer Overpressure Relief Operate
LTC Position at High Limit
LTC Position at Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On

CASE STUDY #3

This system is installed on a power plant Generator Step Up (GSU) transformer. From manual oil samples collected from the transformer, it was found that this GSU was gassing above normal operational parameters. The transformer was taken off line in mid October of 2006 for maintenance. On-Line monitoring is critical for this transformer as failure could result of a loss of revenue exceeding $100K per day.

The customer flushed and filtered the oil and inspected the transformer for any potential problems. A continuous on-line gas PPM monitoring was installed to provide the Power Plant operations indication of combustible gases in the oil.

System Description

This system uses an on-line gas monitor integrated into station RTU which feeds data to the DCS system using Modbus over IP. The on-line gas monitor reports the following data:

- PPM value of composite combustible gas measurement
- Short term and long term rate of change of PPM value of composite combustible gas measurement
- Relative saturation (humidity) of moisture dissolved in oil (%RH)
- Hourly average of %RH and PPM of water in oil
- Computes the PPM water content in oil
- Computes the water in oil condensation temperature

Monitoring these parameters at the plant will help reduce the potential of an unexpected outage due to failure of the transformer.

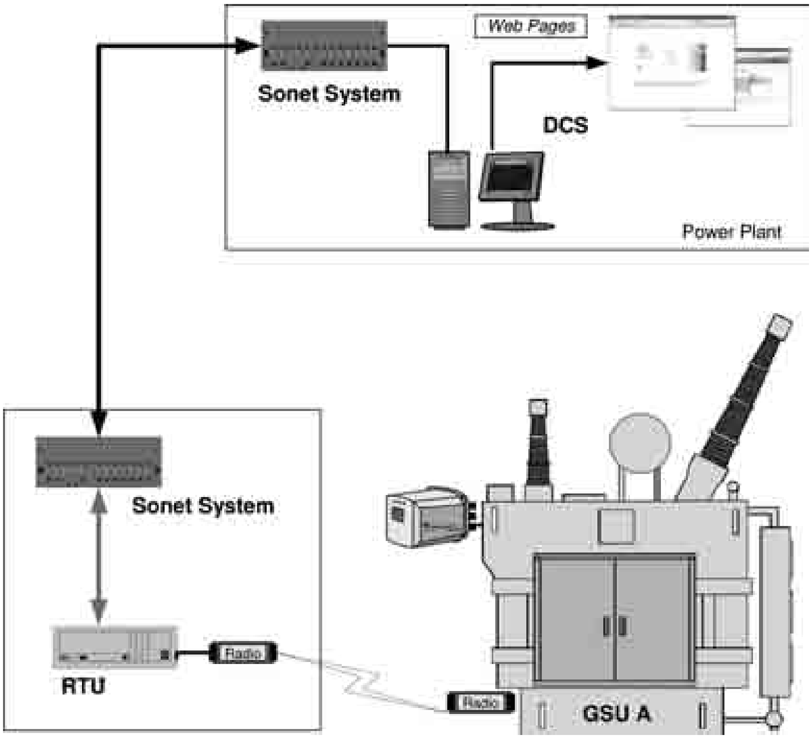


Figure #14: Case #3, System Architecture

CASE STUDY #4

This system is installed at another utility on a series of power plant Generator Step Up (GSU) transformers. This utility had similar concerns about the potential revenue lost from unexpected GSU failure. Much of their fleet of GSU transformers are over 30 years old. This utility also was looking for a method of reducing maintenance costs and loading on limited maintenance resources by moving to a condition based maintenance system. On-Line diagnostics was installed to provide real time information to the plant control operators on their DCS systems and to their SCADA system.

System Description

This system uses an on-line diagnostic system integrated into station DCS using Modbus over IP. All the diagnostic models described in Section II were installed and integrated into the DCS critical data was also provided to the SCADA system via web pages from the DCS system. The on-line diagnostics system was installed because the models reduced the amount of raw data being handled by the operators and the value of calculated output data which then generates an alarm when the model detects a problem. Over 150 gas monitors and 40 diagnostic systems have been installed to date, the utility plans to install an additional 40 units over the next three years.

CASE STUDY #5

This case study describes a system installed on two large 400MVA station transformers.

The utility decided to install a diagnostic system because of the critical nature of these transformers and the costs of an unexpected failure. The diagnostics systems for these transformers, shown in the photos in the following figure, were installed late in 2002.

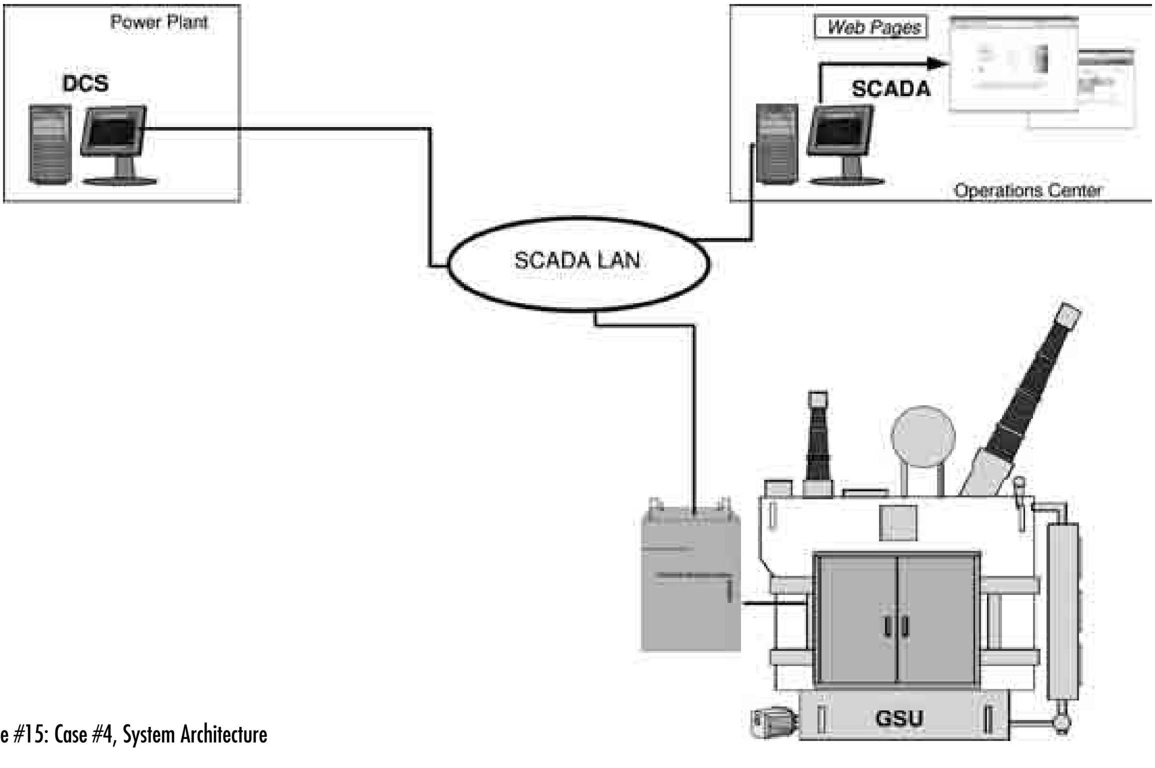


Figure #15: Case #4, System Architecture

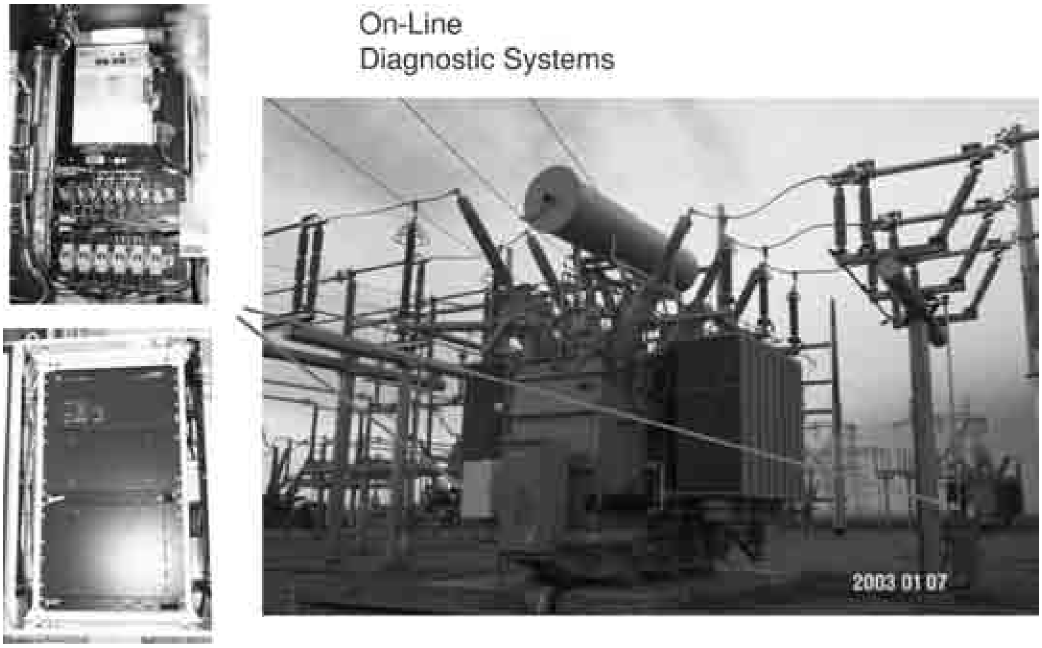


Figure #16: Case #5, Transformer Photos

System Description

This system includes the diagnostics capabilities similar to the previous example but also integrated bushing monitoring. The following listing contains the values being monitored in this case study.

Functions:

- Monitor all critical parameters
- Top Oil Temp
- Ambient Temp
- Bottom Oil Temp
- Dissolved gas in oil
- Moisture in oil
- Load current
- Voltage
- OLTC position
- OLTC remote control
- HV & LV Bushings

The Bushing monitor sensors are installed on the high- and low-voltage bushing on each phase. This allows the system to monitor the leakage current on each bushing and detect potential problems.

This system communicates directly with the SCADA system via DNP 3.0.

CASE STUDY #6

This system highlights a few additional communications and functional capabilities.

First this system provides the diagnostic and monitoring of previous systems, including bushing monitoring.

The communication system between the transformers and the control building consists of a DNP IP communications over the local power line carrier system. It utilizes a secure PLC (Power Line Carrier) system that low-voltage wiring into an intelligent highspeed broadband networking platform. This system is useful when there is no economical method of adding communications between the transformer and the control building. This system also includes a smart gateway which has a DNP connection to a DCS and Https web based server access by authorized users.

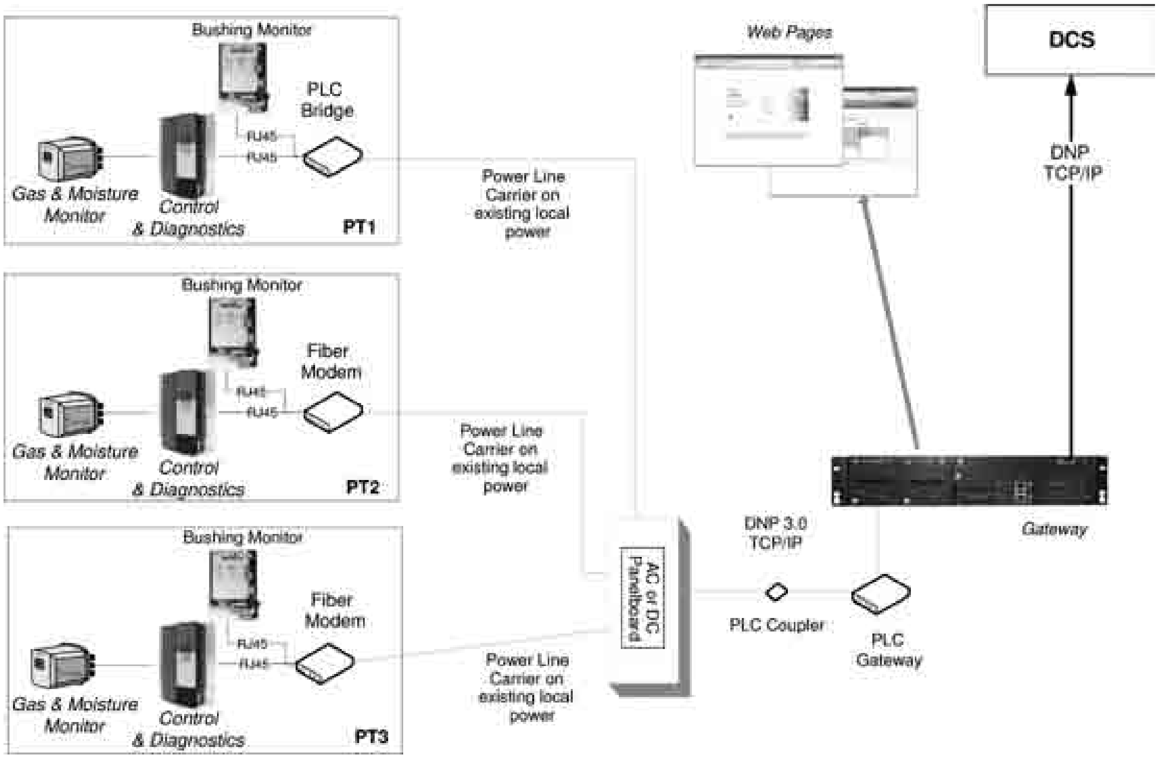


Figure #17: Case #6, System Architecture

CASE STUDY #7

The following system consists of a LTC monitoring system which communicates via dial-up modems. This system provides monitoring on the transformer and the LTC's condition including monitoring the LTC tap operations, tap operation counts, LTC tap wear factors, the temperature difference between the transformer tank and the LTC compartment, the operational characteristics while operating through the various tap positions (LTC Controls), and monitoring the drive motor current and motor index. The utility using this system now performs condition-based maintenance on their LTCs.

They also have credited this system with averting over 30 failures.

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IV. Appendices

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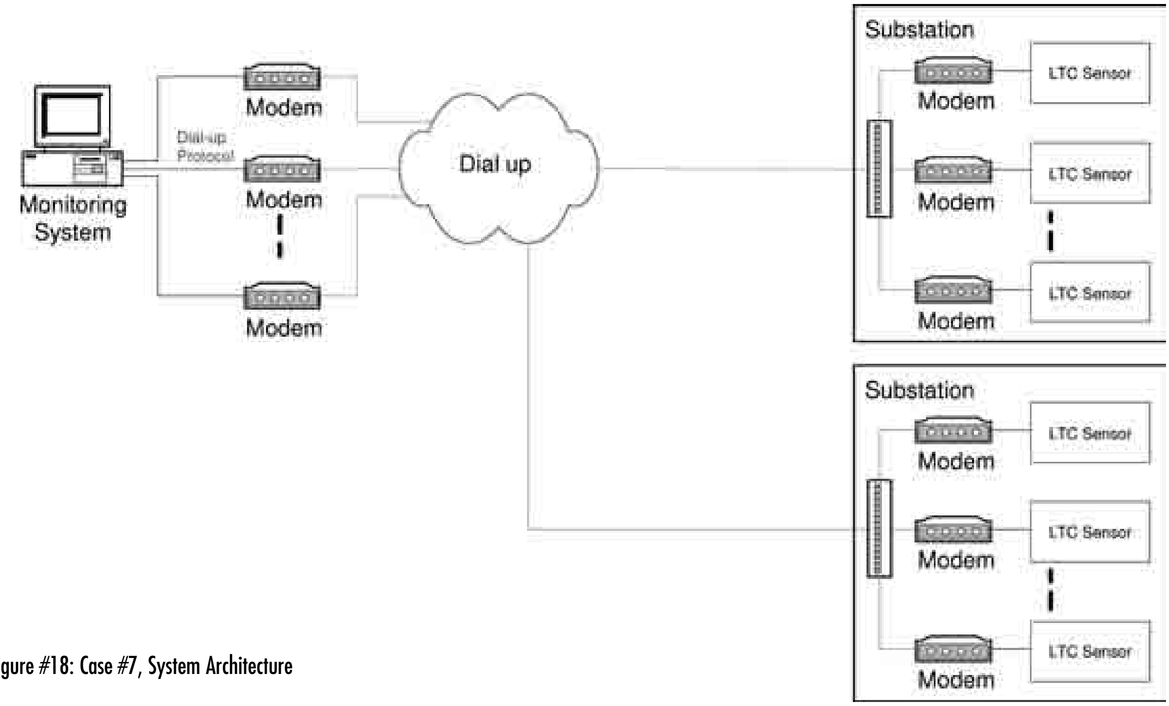

Figure #18: Case #7, System Architecture

Figure #19: Case #7, LTC Sensor Installation

Field validation of moisture and bubbling model:

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POWER TRANSFORMER LOADING

Stephen Cress, Department Manager, Transmission & Distribution Technologies; Kinectrics Inc.

PROJECT OBJECTIVES

The objective of this project for a large North American distribution utility was to provide guidelines for loading of Distribution Station power transformers, along with detailed background rationale for these loading recommendations. The work covered Distribution Station power transformers up to 20 MVA with secondary voltages of 27.6 kV and below.

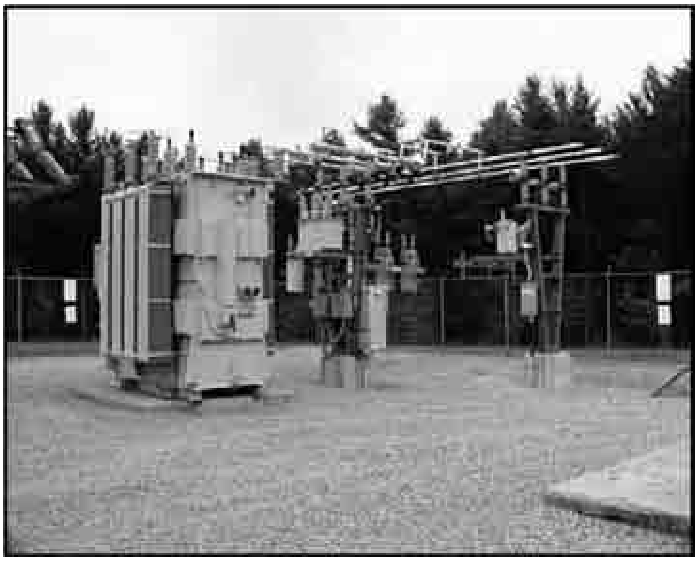
PROJECT CONCLUSIONS

After analysis of the utility's loading policies, transformer types, and the local environment, the study provided the following conclusions:

- In the climate area of the utility in question, station transformer peak loading limits of 160% ONAN rating in the winter and 135% ONAN in the summer were acceptable in terms of loss-of-life. Transformer loading limits of 130% ONAF in the winter and 105% ONAF in the summer were acceptable. Higher loading in emergencies of up to 180% ONAN was considered acceptable in winter without extensive loss-of-life. These levels were proposed as planning target levels at which action was to be initiated to reduce loading. The increased cost of losses while operating at values above these levels was noted as an area of concern.
- Approximately 10% of the utility's Distribution Station transformers had peak loads beyond acceptable levels and would be subject to accelerated loss-of-life.
- Benchmarked against others, this utility loaded many Distribution Station power transformers beyond the levels applied by similar installations. This philosophy was based on using Mobile Unit Substations in the event of failure, as opposed to a dual transformer scheme.
- Many factors were considered when choosing the appropriate loading, including loss-of-life, hot spot temperatures, total ownership cost, current economic parameters, the treatment of loss costs, and the effects on thermal loading limitations of ambient temperature and use of auxiliary cooling.

The study also included a review of the impacts of loading on the life and health of Under Load Tap Changers (ULTCs). Some conclusions regarding ULTCs were as follows:

- ULTCs were the major cause of transformer failures at this utility. ULTCs can experience 60,000 to 80,000 operations in 5 years. The ANSI C37.131 standard requires a service duty test of 50,000 operations.
- Little information was available on the effect of loading on ULTC life other than qualitative statements that high loading can accelerate contact erosion and contact wear may be proportional to the square of the current. Coking of ULTC contacts increases the contact resistance and increases heating, possibly leading to thermal runaway.
- The ANSI Standard C57.131 indicates that ULTCs should be designed to match the performance specified in applicable transformer loading guides and should not exceed 20° C rise at 120% rated load. There was insufficient evidence to indicate that ULTCs impose limits beyond those for transformer loadability, particularly considering that ULTCs are maintainable and replaceable. Therefore their effect on transformer loss-of-life is reversible to some degree.



EFFECTIVE RECOMMENDATIONS

- It was recommended that the utility take action to reduce loading or increase the capacity of the out-lyer Distribution Station transformers that are operating beyond the acceptable limits.
- Remote monitoring of the transformer temperature was highly recommended for transformers that have planned loading above rated levels. A low-cost monitoring system at critical Distribution Stations would be an appropriate method to extend the life of transformer assets and defer capital expense. Acoustic and temperature differential monitoring is available for underload tap changers. Knowledge of the transformer loading history is the first step in applying Reliability-Centered Maintenance (RCM).
- Loading guidelines must be applied to the appropriate air-cooled or forced-air ratings of the transformers.
- Testing and model development to evaluate the effects of loading and temperature on the life expectation of ULTCs would advance the state of the art.
- Development is required to obtain typical loading profiles based on monitoring information from DSs.
- This utility was well suited for Demand Management initiatives that would improve load factors on power transformers, thereby extending equipment life and deferring capital expenditure.

COST JUSTIFYING TRANSFORMER MONITORING

Mark Tostrud, Dynamic Ratings, Inc.

Utilities are producing and distributing more power, running assets harder, but the budgets and manpower used to service and support the infrastructure is shrinking. Transformer monitoring is proving to be a key element in helping managers survive in a work environment that continually expects more to be achieved with less.

Utilizing data collected from generation, transmission and distribution utilities, we have been able to help customers evaluate what type of transformer monitoring is cost justified, how to best implement the monitoring and how to utilize the information to ensure that the benefits are gained.

INTRODUCTION

"Since the mid 1980s, equipment utilization ratios (the ratio of peak loading to equipment capability) has risen through the power industry as electric distribution utilities sought to increase efficiency of equipment usage and cut back on expenses. It was not uncommon to see an electric distribution utility raise its target utilization ratio for transformers from 66%, about typical for the mid 1970s, to 70-83% during the last 15 years of the 20th century." Today, it is common to find portions of utility systems across the country with utilization ratios exceeding 90% and in some extreme situations, exceeding 100% under peak load conditions. [1]

At the same time utilization ratios were increasing, asset managers saw their operating and maintenance budgets reduced by 25-50% over the same period. While initial budget reductions were easily absorbed by extending maintenance frequencies with virtually no reduction in reliability, the success of these initial changes resulted in continuing pressure to reduce operating costs by further extending maintenance cycles until reliability began to suffer.

Increasing equipment failures resulted in many companies looking for ways to condition monitor their equipment as a means to reduce costs while at the same time monitor the health of their system. For transformers, new ways to condition monitor the equipment through periodic oil samples, infrared surveys and a variety of online and offline testing were identified and implemented. While these time-based condition-monitoring tasks helped prove the validity of these techniques to correctly identify transformer problems, they also accented the inherent flaws in the time-based approach. To be effective, condition monitoring needs to provide sufficient advance warning of impending problems to allow outages to be scheduled and planned. This cannot be accomplished using the traditional time based approach since many failures do not provide significant warning signs until a short time before the impending failure.

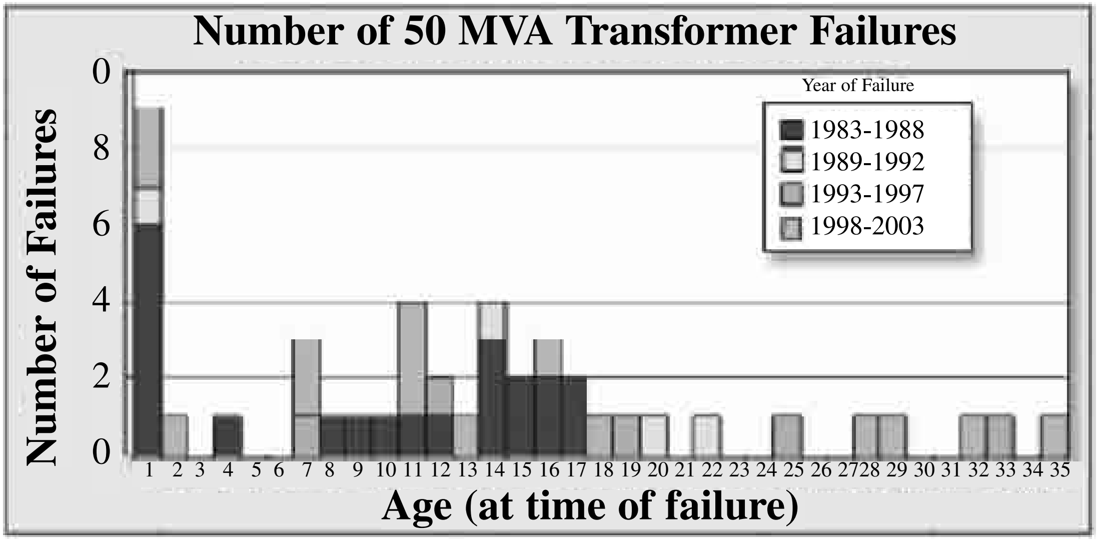


Figure 1 – Utility Failure Data [2]

To survive in today's regulatory environment and competitive marketplace, utilities must adopt online monitoring systems to provide the timely, accurate and meaningful information asset managers require to adequately predict equipment failures and impending end of life issues.

Although most asset managers recognize the need for improved transformer monitoring, many struggle with deciding what type of monitoring is required and how to justify the cost of this equipment. Often the same information used to identify what type of monitoring is required can be used to cost justify the equipment as well.

FACTORS TO CONSIDER WHEN IDENTIFYING AND COST JUSTIFYING TRANSFORMER MONITORING

FAILURE PREVENTION

All transformers left in service will eventually fail. While some will last longer than others, two identical transformers manufactured to the same design, installed in the same substation with identical operating and maintenance histories can provide dramatically different service life.

Unfortunately, the time to failure on transformers is relatively unknown. Many transformer problems and failures occur in the first few months of service. Even if these infant mortality issues are covered under warranty, the impact and incidental costs to the utility can be significant. The following data illustrates the infant mortality failures experienced by one medium sized utility.

Following the first year of service, the transformer is then statistically very reliable until it starts to reach its end-of-life. Willis explains the challenges in predicting a transformer's end-of life in Aging Power Delivery Infrastructures.

With present (periodic testing) technologies, it does not seem possible to predict time-to-failure exactly. In fact, capability in failure prediction for equipment is about the same as it is for human beings.

1. Time-to-failure can be predicted accurately only over a large population (set of unit). Children born in 2000 in the United States have an expected lifetime of 76 years, with a standard deviation of 11 years. Service transformers put into service in 2000 have an average expected lifetime of 43 years with a standard deviation of 7 years

2. Assessment based on time-in-service can be done, but still leads to information which is accurate only when applied to a large population. Thus, analysts can determine that people who have reached age 50 in year 2000 have an expected 31 years of life remaining. Service transformers that have survived 30 years in service have an average 16 years of service remaining.

3. Condition assessment can identify different expectations based on past or existing service conditions, but again this is only accurate for a large population. Smokers who have reached age 50 have only a remaining 22 years of expected lifetime, not 31. Service transformers that have seen 30 years service in high-lightning areas have an average of only 11 years service life remaining, not 16.

4. (Periodic) Tests can narrow but not eliminate the uncertainty in failure prediction of individual units. All medical testing in the world cannot predict with certainty the time of death of an apparently healthy human being, although it can identify flaws that might indicate likelihood for failure.

Similarly, testing of a power transformer will identify if it has a "fatal" flaw in it. But if a human being or a power system unit gets a "good bill of health", it really means that there is no clue to when the unit will fail, except that that failure does not appear to be imminent.

5. Time to failure of an individual unit is only easy to predict when failure is imminent. In cases where failure is due to "natural causes" (i.e., not due to abnormal events such as being in an auto accident or being hit by lightning), failure can be predicted only a short time prior to failure. At this point, failure is almost certain to advanced stages of detectable deterioration in some key component.

Thus, when rich Uncle Jacob was in his 60s and apparently healthy, neither his relatives nor his doctors knew whether it would be another two years or two decades before he died and his will was probated. Now that he lies on his deathbed with a detectable bad heart, failure within a matter of days is nearly certain. The relatives gather.

Similarly, in the week or two leading up to failure, a power transformer generally will give detectable signs of impending failure: an identifiable acoustic signature will develop, there will be internal gassing, and perhaps detectable changes in leakage current, etc. [3]

This random nature of transformer failures makes it extremely difficult to capture impending failures using periodic time based condition monitoring techniques. The presence of on line transformer monitoring can greatly improve the ability to capture impending failures early enough to allow a scheduled shutdown and outage thereby preventing major failures.

FAILURE HISTORY

Failure history is the first factor that should be considered when selecting what type of transformer monitoring should be installed. In the absence of utility specific failure data, industry data can be used. The data, shown in figure 1, was obtained from Doble Engineering Company's review of transformer failures from 1993-1998 [4]:

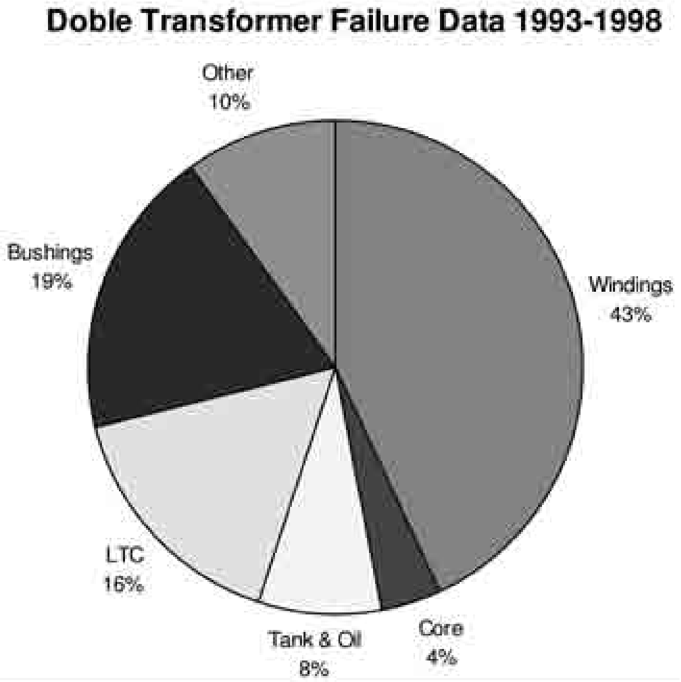


Figure 2 - Doble Engineering Transformer Failure Data 1993-1998

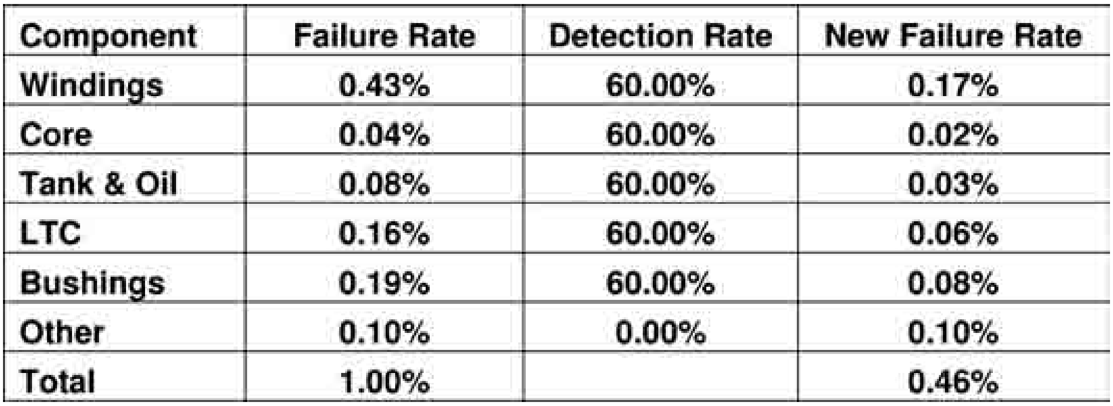
Comprehensive transformer monitoring systems can be designed to economically monitor most of the transformer failure modes shown above. With a properly designed system, detection rates of at least 60% are easily achievable. For a transformer with a 1% overall failure rate, a new failure rate with a comprehensive monitoring system installed can be calculated as follows on next page:

The savings due to the improved reliability of a transformer could then be calculated as:

(Existing Failure Rate – New Failure Rate) x Cost of a New Transformer Cost Savings due to improved reliability = (1%-.46%) x $2,000,000 = $10,800 USD per year

REDUCED MAINTENANCE COSTS

Since on-line monitoring systems can also provide a reduction in maintenance costs, understanding the existing costs associated with a transformer or fleet of transformers is the second important element which should be considered. The maintenance costs associated with each transformer can vary significantly depending upon the overall condition of the transformer,

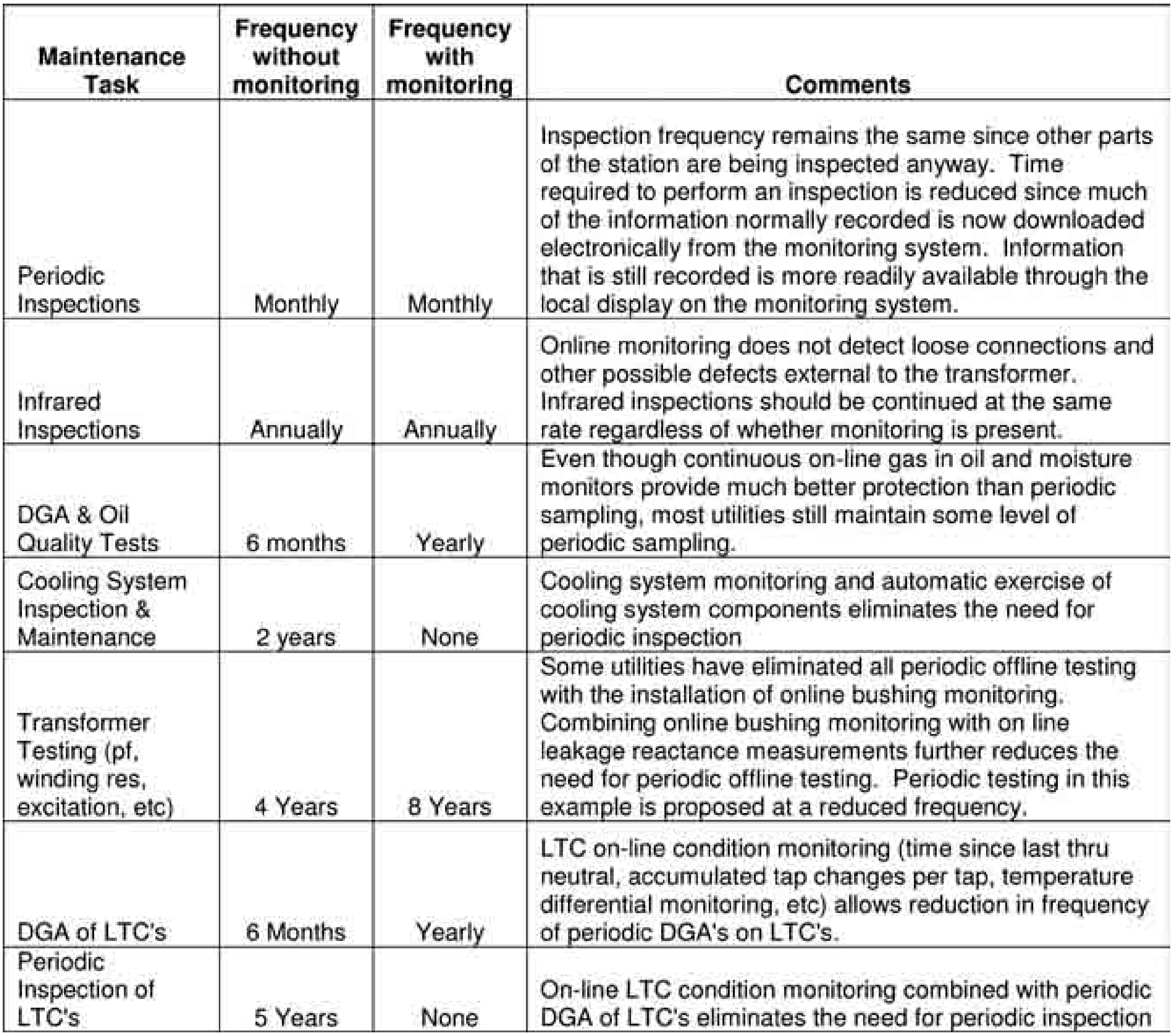


Component	Failure Rate	Detection Rate	New Failure Rate
Windings	0.43%	60.00%	0.17%
Core	0.04%	60.00%	0.02%
Tank & Oil	0.08%	60.00%	0.03%
LTC	0.16%	60.00%	0.06%
Bushings	0.19%	60.00%	0.08%
Other	0.10%	0.00%	0.10%
Total	1.00%		0.46%

Table 1 – Improved Failure Rate with Monitoring

its loading, operation and maintenance history as well as other factors. This information needs to be considered to ensure the monitoring system addresses the major cost drivers in a utility's transformer maintenance program.

The installation of a comprehensive monitoring system will allow the end user to eliminate some maintenance tasks while extending the frequencies of other tasks.



Maintenance Task	Frequency without monitoring	Frequency with monitoring	Comments
Periodic Inspections	Monthly	Monthly	Inspection frequency remains the same since other parts of the station are being inspected anyway. Time required to perform an inspection is reduced since much of the information normally recorded is now downloaded electronically from the monitoring system. Information that is still recorded is more readily available through the local display on the monitoring system.
Infrared Inspections	Annually	Annually	Online monitoring does not detect loose connections and other possible defects external to the transformer. Infrared inspections should be continued at the same rate regardless of whether monitoring is present.
DGA & Oil Quality Tests	6 months	Yearly	Even though continuous on-line gas in oil and moisture monitors provide much better protection than periodic sampling, most utilities still maintain some level of periodic sampling.
Cooling System Inspection & Maintenance	2 years	None	Cooling system monitoring and automatic exercise of cooling system components eliminates the need for periodic inspection
Transformer Testing (pf, winding res, excitation, etc)	4 Years	8 Years	Some utilities have eliminated all periodic offline testing with the installation of online bushing monitoring. Combining online bushing monitoring with on line leakage reactance measurements further reduces the need for periodic offline testing. Periodic testing in this example is proposed at a reduced frequency.
DGA of LTC's	6 Months	Yearly	LTC on-line condition monitoring (time since last thru neutral, accumulated tap changes per tap, temperature differential monitoring, etc) allows reduction in frequency of periodic DGA's on LTC's.
Periodic Inspection of LTC's	5 Years	None	On-line LTC condition monitoring combined with periodic DGA of LTC's eliminates the need for periodic inspection

Table 2 – Typical Maintenance Frequencies Before and After Transformer Monitoring

The following is an example of cost savings that can be achieved through the installation of transformer monitoring:

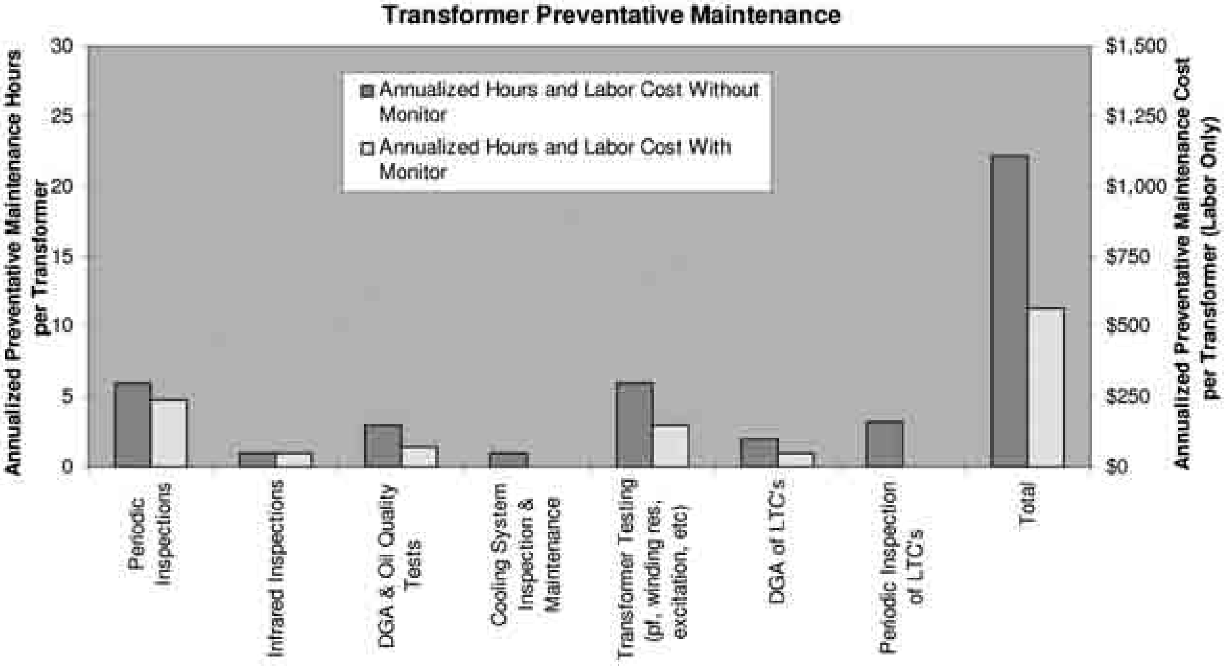


Figure 3 - Representative Transformer Preventative Maintenance Savings

The savings shown above are typical savings that can be expected through the installation of a monitoring system.

While savings can be achieved through reduced routine maintenance costs, often more significant savings are achieved through capturing corrective maintenance issues earlier.

- In April of 2006, the cooling system Minor alarm (Cool Fail monitoring alarm) lead to the discovery of a failed winding temperature control/gauge. The winding temperature gauge controls the second stage of cooling as well as provides alarms for High Winding temperature. The second stage of cooling and the high temperature alarm were malfunctioning. This was a new 300MVA transformer that had been in service less than 1 year. This catch prevented overheating and resulting damage to the transformer during peak load summer conditions. Additionally, monitoring data spotted an intermittent fan failure, which was covered under warranty. While these problems would not have resulted in a failure, they could have reduced the service life of the transformer due to increased thermal aging.
- In July 2004, A High Delta Temperature monitor alarm triggered a DGA sample to be taken. The LTC was on a six-month DGA cycle and the last DGA was taken only 33 days earlier. It would have been December before the next DGA would have been taken. The Methane, Ethylene and Ethane had risen significantly. The overheated components were replaced and the unit was put back into service thereby avoiding a potentially serious unplanned outage.
- In December 2001, a dual LTC 70MVA was taken out of service when major and minor alarms were generated by on-line monitoring equipment. Inspection revealed that the transformer had a dangerous level of combustible gas, arcing at the CT lead penetration and excessive LTC wear.

While the savings associated with each problem identified and corrected at an early stage will vary, the cost of performing scheduled work is typically 30-50% less than the costs of performing unscheduled work. Among the factors associated with the higher cost of performing unscheduled work are: overtime pay, planning, coordination and scheduling of unplanned outages as well as parts, equipment and manpower availability. In addition to providing early warning of impending problems, most advanced monitoring systems have the ability to categorize transformer alarms allowing the end user to identify the appropriate response level thereby improving the ability to schedule and plan transformer maintenance issues.

Typically, utilities employing on-line transformer monitoring have experienced a 30-50% overall reduction in unplanned transformer maintenance costs.

INCREASED RISK OF OUTAGES DUE TO HIGHER UTILIZATION RATIOS

As transformer utilization ratios increase, transformers have less bridging capacity available to handle loads from other transformers in the event of a failure. With less emergency bridging capacity available, the number of neighboring transformers required to pick up load from a failed transformer increases. As the number of transformers involved in a bridging scheme increases, the probability of an extended outages increases. Managing the risk associated with higher utilization ratios is the third element that should be taken into account when considering transformer monitoring.

Consider two 100 MVA transformers each serving a load of 60 MVA. In the event of a failure, the remaining transformer could be expected to serve the combined load of 120 MVA. While the transformer aging would increase, loading a transformer to 120% of nameplate under a first contingency emergency is considered an acceptable utility practice. The probability of an extended outage due to the failure of both transformers assuming a 1% failure rate could then be calculated as:

Failure probability of 1st transformer x Failure probability of 2nd transformer =

$$.01 \times .01 = .0001$$

However, as the transformer utilization ratio increases with each transformer now serving 75 MVA, the remaining transformer would no longer be able to carry the combined load in the event of a failure without exceeding the transformer emergency rating of 120%. Since a third transformer would also be required to pick up a portion of the load from the failed transformer, the risk of an extended outage would increase. In the case of three transformers, an extended outage would occur if all three transformers fail or if any of the two transformers fail. The probability of an extended outage in the case of three transformers can be calculated as:

$$\text{Extended Outage Probability} = .01^3 + 3x(.01^2x(1-.01))=.000298$$

Therefore, the probability of an extended outage increases nearly 3 times when the utilization ratio is increased from 60% of nameplate to 75% of nameplate. [5]

However, consider the same three transformers that have improved reliability due to the installation of the transformer monitoring system from the earlier example. The installation of transformer monitoring decreases the probability of an extended outage by nearly 5 times:

$$\text{Extended Outage Probability} = .0046^3 + 3x(.0046^2x(1-.0046))=.000063$$

Therefore, as transformer utilization ratios increase, the probability of extended outages increases. However, the installation of comprehensive transformer monitoring on these same transformers allows the asset manager to increase utilization ratios while at the same time reduce the risk of extended outages and improve the overall reliability of the system. Reducing the risk of extended outages becomes even more important when faced with potential outage penalties.

DEFERRED TRANSFORMER REPLACEMENT COSTS

Many utilities throughout the world have begun to place significant focus on the age of their installed transformer fleet. In the US, the average age of the installed transformer fleet is approximately 30 years old as shown in figure 4. [6]

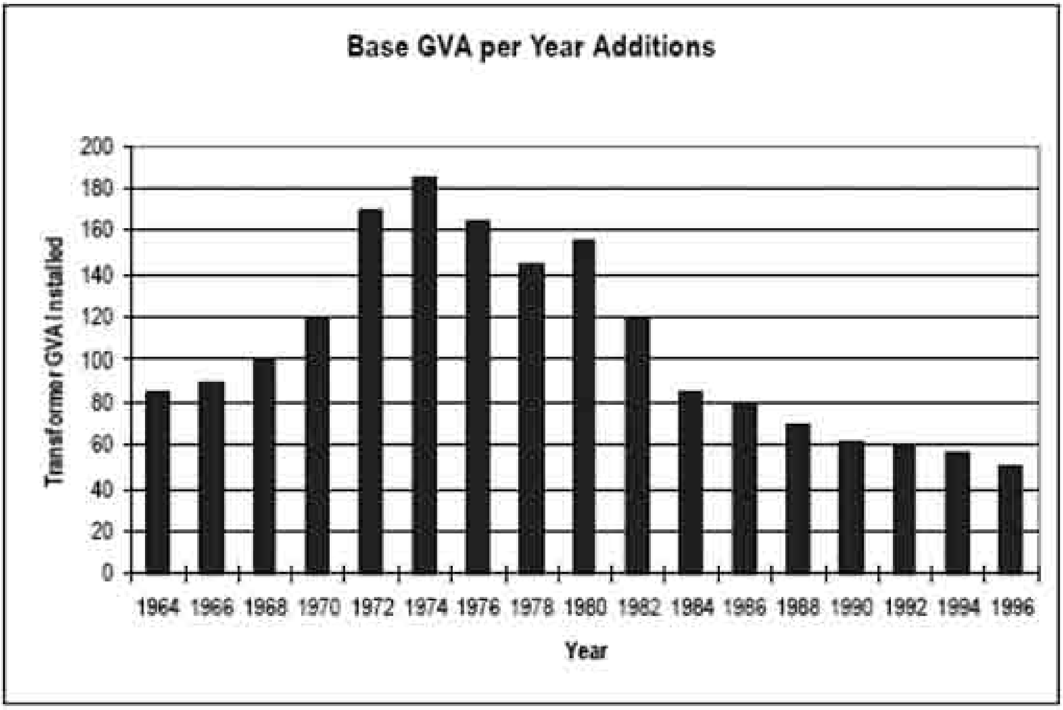


Figure 4 - US Installed Transformer Fleet

To address this problem, many utilities have implemented system renewal programs based on the assumed condition of these transformer assets. To accurately assess the true condition of a transformer requires knowledge of the maintenance history, loading and fault history as well as a series of electrical and chemical tests to determine the overall health of the unit. However, even with the best of information, "time to failure of an individual unit is only easy to predict when failure is imminent." [7] As the cost and lead times associated with new transformers continue to increase, the installation of transformer monitoring is becoming more common to help manage these costs and make informed decisions on which transformers should be replaced. The cost savings achieved by a deferring a $1 million transformer replacement one year assuming a 6% cost of capital is sufficient to offset the cost of the transformer monitor as shown in the following example:

Cost Savings Achieved by Deferring Replacement 1 year = Transformer Cost x Interest Rate = $1,000,000x(.06) = $60,000

Savings due to the deferral of transformer replacements is the fourth element that should be taken into account when considering transformer monitoring.

COST OF LOST GENERATION

In our opinion, the costs associated with lost generation make it financially irresponsible not to utilize transformer monitoring in most GSU applications. The cost of lost generation often results in greater financial penalties than the cost of the transformer failure itself.

West Virginia, USA - Jul 18, 2006 – A transformer failure shut down one unit at… Harrison Power Station, causing an outage that the company estimates will cost at least $10 million in lost revenues and repair expenses. The transformer, located in a 500-kilovolt transmission facility adjacent to the power station, failed on Saturday and the 651- megawatt Harrison Unit 1 automatically shut down. The company said it expects Unit 1 to return to service by mid- August. [8]

Although not every transformer failure can be prevented through transformer monitoring, the early warning offered through a comprehensive transformer monitoring system significantly lowers the risk of an unscheduled outage. Since early identification allows for better outage planning, the severity of the problem and the outage duration should be reduced. The cost savings that would be achieved through the prevention of a single failure can be easily calculated as:

Gen Capacity Lost x Reduced Outage Duration x Generation Costs (Gas-Coal)

500 MW x 7 days x 24 hrs/day x ($60MWH – $30 MWH) = $2.5 Million USD

The annual benefit (avoided cost) achieved through the presence of on-line monitoring for a transformer using the failure data from the earlier example can be calculated as:

Annual Benefit = Gen Capacity Lost x Reduced Outage Duration x Generation Cost (Gas-Coal) x Improved Failure Rate = 500 MW x 7 days x 24 hrs/day x ($60MWH – $30 MWH) x (.01-.0046) = $13,608

While one would typically only think of generator step up transformer applications when considering the cost of generation in the justification of a monitoring system, the availability and cost of generation can be affected by transmission system transformer failures as well. Millions of dollars are exchanged each day in the power marketing arena based on the transmission system's ability to transport available generation. A single unscheduled outage can have dramatic impacts on both the cost and quantity of power being purchased and sold.

INCREASED SYSTEM RISK DUE TO SCHEDULED MAINTENANCE

Although outages associated with routine maintenance have often been considered a required and acceptable risk by most utilities, outage penalties and the increased focus on indices for outage frequency and duration is beginning to play a major role in the types and duration of the outages granted. Each time a routine maintenance outage is granted, the risk of an outage on the remaining part of the system increases.

1. At about 0704 PST on February 26, 2000, a three-phase fault occurred on the... North 220 kV bus. The fault occurred when an operator inadvertently closed the North 220 kV bus ground disconnects while attempting to close the transformer bank (220/66 kV) ground disconnects during switching to clear the bank. The 220 kV bus differential relay failed to operate causing all source lines into the… substation to open at remote ends of the lines. [9]

2. At 1701 EST, system protection removed from service four high voltage transmission lines. Three of the affected transmission lines share a common right of way. One of the transmission lines was carrying additional load because of a planned outage on a high-voltage transformer. During the disturbance, service was interrupted to about 46,000 customers (196 MW). At about 19:47 EST, system operators restored all customer demands and much of the affected transmission. [10]

3. On Saturday, April 1, 2000, at 08:52 EST, a potential transformer at the…(name omitted) Substation failed, causing all circuit breakers at the station to open… remaining generating resources were insufficient to supply the demand, resulting in a drop in frequency and system protection subsequently removed the… generating facility from service. Due to routine maintenance being performed at the time… had the electric supply interrupted to three substations, which also were supplied through the… Substation. [11]

CONCLUSIONS

Utilities are producing and distributing more power, running assets harder but the budgets and manpower used to service and support the infrastructure is shrinking. Nearly every utility in the world is faced with budget constraints which are preventing them from performing all of the maintenance and infrastructure improvements they feel are required. "Only by innovating, by taking a new approach and changing the way they plan, engineer, operate and, in particular, manage their systems, can utilities get both the system and financial performance they need." [12]

For many asset managers, transformer monitoring is proving to be a key element in helping them survive in a work environment that continually expects more to be achieved with less. While in the past, asset managers may have found it difficult to justify the cost of monitoring their transformers, the benefits, cost avoidance and savings associated with the installation of transformer monitoring offer the ability to turn what used to be considered an expense into an investment in the future.

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BIOGRAPHY

Mark Tostrud is the Engineering Manager for Dynamic Ratings, Inc. Prior to his present position, Mark was a Construction & Maintenance Supervisor at We Energies. During his 19 years at We Energies, Mark lead the implementation of many of the condition-based monitoring programs for We Energies' substation equipment.

ENERGY LOSSES

Tony R. Kuphaldt

When transformers transfer power, they do so with a minimum of loss. Modern power transformer designs typically exceed 95% efficiency. It is good to know where some of this lost power goes, however, and what causes it to be lost.

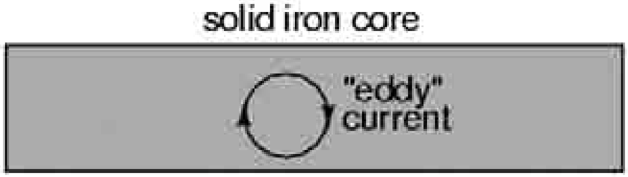
There is, of course, power lost due to resistance of the wire windings. Unless superconducting wires are used, there will always be power dissipated in the form of heat through the resistance of current-carrying conductors. Because transformers require such long lengths of wire, this loss can be a significant factor. Increasing the gauge of the winding wire is one way to minimize this loss, but only with substantial increases in cost, size, and weight.

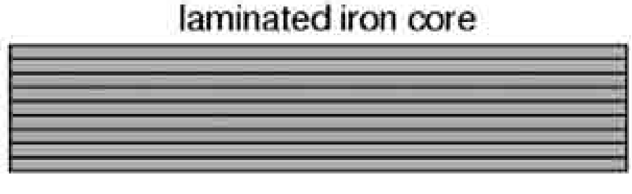
Resistive losses aside, the bulk of transformer power loss is due to magnetic effects in the core. Perhaps the most significant of these "core losses" is eddy-current loss, which is resistive power dissipation due to the passage of induced currents through the iron of the core. Because iron is a conductor of electricity as well as being an excellent "conductor" of magnetic flux, there will be currents induced in the iron just as there are currents induced in the secondary windings from the alternating magnetic field. These induced currents - as described by the perpendicularity clause of Faraday's Law - tend to circulate through the cross-section of the core perpendicularly to the primary winding turns. Their circular motion gives them their unusual name: like eddies in a stream of water that circulate rather than move in straight lines.

Iron is a fair conductor of electricity, but not as good as the copper or aluminum from which wire windings are typically made. Consequently, these "eddy currents" must overcome significant electrical resistance as they circulate through the core. In overcoming the resistance offered by the iron, they dissipate power in the form of heat. Hence, we have a source of inefficiency in the transformer that is difficult to eliminate.

This phenomenon is so pronounced that it is often exploited as a means of heating ferrous (iron-containing) materials. The following photograph shows an "induction heating" unit raising the temperature of a large pipe section. Loops of wire covered by high-temperature insulation encircle the pipe's circumference, inducing eddy currents within the pipe wall by electromagnetic induction. In order to maximize the eddy current effect, high-frequency alternating current is used rather than power line frequency (60 Hz). The box units at the right of the picture produce the high-frequency AC and control the amount of current in the wires to stabilize the pipe temperature at a pre-determined "set-point."

The main strategy in mitigating these wasteful eddy currents in transformer cores is to form the iron core in sheets, each sheet covered with an insulating varnish so that the core is divided up into thin slices. The result is very little width in the core for eddy currents to circulate in:





Laminated cores like the one shown here are standard in almost all low-frequency transformers. Recall from the photograph of the transformer cut in half that the iron core was composed of many thin sheets rather than one solid piece. Eddy current losses increase with frequency, so transformers designed to run on higher-frequency power (such as 400 Hz, used in many military and aircraft applications) must use thinner laminations to keep the losses down to a respectable minimum. This has the undesirable effect of increasing the manufacturing cost of the transformer.

Another, similar technique for minimizing eddy current losses which works better for high-frequency applications is to make the core out of iron powder instead of thin iron sheets. Like the lamination sheets, these granules of iron are individually coated in an electrically insulating material, which makes the core nonconductive except for within the width of each granule. Powdered iron cores are often found in transformers handling radio-frequency currents.

Another "core loss" is that of magnetic hysteresis. All ferromagnetic materials tend to retain some degree of magnetization after exposure to an external magnetic field. This tendency to stay magnetized is called "hysteresis", and it takes a certain investment in energy to overcome this opposition to change every time the magnetic field produced by the primary winding changes polarity (twice per AC cycle). This type of loss can be mitigated through good core material selection (choosing a core alloy with low hysteresis, as evidenced by a "thin" B/H hysteresis curve), and designing the core for minimum flux density (large cross-sectional area).

Transformer energy losses tend to worsen with increasing frequency. The skin effect within winding conductors reduces the available cross-sectional area for electron flow, thereby increasing effective resistance as the frequency goes up and creating more power lost through resistive dissipation. Magnetic core losses are also exaggerated with higher frequencies, eddy currents and hysteresis effects becoming more severe. For this reason, transformers of significant size are designed to operate efficiently in a limited range of frequencies. In most power distribution systems where the line frequency is very stable, one would think excessive frequency would never pose a problem. Unfortunately it does, in the form of harmonics created by nonlinear loads.

Nonsinusoidal waveforms are equivalent to additive series of multiple sinusoidal waveforms at different amplitudes and frequencies. In power systems, these other frequencies are whole-number multiples of the fundamental (line) frequency, meaning that they will always be higher, not lower, than the design frequency of the transformer. In significant measure, they can cause severe transformer overheating. Power transformers can be engineered to handle certain levels of power system harmonics, and this capability is sometimes denoted with a "K factor" rating.

TRANSFORMER/LINE LOSS CALCULATIONS

Schneider Electric

OVERVIEW

Loss Compensation is used when a meter's actual location is different from the electrical location where change of ownership occurs; for example, where meters are connected on the low-voltage side of power transformers when the ownership change occurs on the high-side of the transformer. This physical separation between meter and actual billing point results in measurable losses. Compensating for this loss - Loss Compensation - is the means of correcting this meter reading.

Losses may be added to or subtracted from the meter registration.

Meters are usually installed on the low-voltage side of a transformer because it is more cost-effective. There are also cases where change of ownership may occur halfway along a transmission line where it is impractical to install a meter. In this case, power metering must again be compensated.

LINE LOSS AND TRANSFORMER LOSS AFTER THE PCC

The PCC (Point of Common Coupling) is the interchange point between the distribution grid and a particular customer. Unlike losses that occur within a transmission/distribution network, which cannot be allocated to a single customer and must be rolled into the per-unit cost of electricity, losses that occur after the PCC can be measured and allocated accordingly.

Element	Definition
$\frac{r}{l}$	Per unit length resistance
$\frac{x}{l}$	Per unit length reactance
L	Total length in units
R	Resistive component
Z	Impedance
P_{loss}	Active power loss
X	Reactive component
Q_{loss}	Reactive power loss

CAUSES OF LINE LOSS

Line Losses are a result of passing current through an imperfect conductor such as copper. The conducting material has characteristic impedance that produce, a voltage drop along the line proportional to the current flow. The total line impedance can be determined from the elements on the presious chart:

The resistive component (R) of the impedance (Z) contributes to active power losses (Ploss), while the reactive component (X) contributes to reactive power losses (Qloss).

The line-losses can be calculated based on the measured current load as:

$$LLW = P_{loss} = I \times \left(I \times \frac{r}{l} \times L\right) = I^2 \times R \quad (1)$$

$$LLV = Q_{loss} = I \times \left(I \times \frac{x}{l} \times L\right) = I^2 \times X \quad (2)$$

For a 3-phase system, the losses for each phase are calculated separately according to the measured current as:

$$P_{loss-tot} = (P_{loss-a} + P_{loss-b} + P_{loss-c}) = (I_a^2 \times R_a + I_b^2 \times R_b + I_c^2 \times R_c) \quad (3)$$

$$Q_{loss-tot} = (Q_{loss-a} + Q_{loss-b} + Q_{loss-c}) = (I_a^2 \times X_a + I_b^2 \times X_b + I_c^2 \times X_c) \quad (4)$$

If we assume that the per-phase impedance is similar and use the average impedance, the equation simplifies to:

$$LLW = P_{loss-avg} = \frac{(I_a^2 + I_b^2 + I_c^2)}{3} \times R = I^2{}_{avg} \times R \quad (5)$$

$$LLV = Q_{loss-avg} = \frac{(I_a^2 + I_b^2 + I_c^2)}{3} \times X = I^2{}_{avg} \times X \quad (6)$$

CAUSES OF TRANSFORMER LOSS

Power transformer losses are a combination of the power dissipated by the core's magnetizing inductance (Iron loss) and the winding's impedance (Copper loss).

Iron losses are a function of the applied voltage and are often referred to as "noload losses" - they are induced even when there is no load current. Copper losses are a function of the winding current and are often referred to as "load losses".

These losses are calculated for any operating condition if a few parameters of the power transformer are known. The transformer manufacturer commonly provides this information on the transformer test sheet:

- rated total kVA of the power transformer (VATXtest).
- rated voltage of the power transformer (VTXtest).

- No-load test watts (LWFeTXtest) - the active power consumed by the transformer's core at the rated voltage with no load current (open circuit test).
- Full-load test watts (LWCuTXtest) - the active power consumed by the transformer's windings at full load current for rated kVA (short circuit test).
- %Excitation current - ratio of No-load test current (at rated voltage) to full load current.
- %Impedance - ratio of Full-load test voltage (at rated current) to rated voltage.

The No-Load and Full-Load VAR losses (LVFeTXtest and LVCuTXtest) may not be provided, but are calculated from the above data.

$$LVFe_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Excitation}{100}\right)^2 - (LWFe_{TXtest})^2}$$

$$LVCu_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Impedance}{100}\right)^2 - (LWCu_{TXtest})^2}$$

To determine the actual transformer losses, the test losses must be scaled for use at the actual operating voltage and current.

$$LWFe = LWFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^2 \tag{9}$$

$$LVFe = LVFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^4 \tag{11}$$

$$LWCu = LWCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \tag{10}$$

$$LVCu = LVCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \tag{12}$$

LOSS COMPENSATION IN ION METERS

ION meters that support loss compensation in their default framework are the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters. For information about Loss Compensation in the ION7700 and ION7300 series, please contact Schneider Electric.

The meters have the following Transformer and Line Loss Compensation features:

- Compensation performed on 1-second total power (kW total, kVAR total, and kVA total).
- Unbalanced loads are handled accurately (except in the case of line-loss of neutral conductor in a 4-Wye system).
- Losses may be added or subtracted.
- Compensation works in all four power quadrants.
- Compensation is available in TEST mode. Support for compensation on singlephase test sets is also available in TEST mode.
- Compensation works correctly when all revenue parameters are reported in secondary units (meter units).

By default, the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters come configured to provide the following compensated registers:

For Total kW, Total kVAR, and Total kVA quantities:

- Real-time power
- Demand: Thermal and Block
- Calibration Pulsers
- Min/Max

For Total kWh, Total kVARh, and Total kVAh quantities:

- Energy
- Interval Energy
- Energy in Test Mode
- Energy for each TOU rate

The ION8300/ION8400/ION8500 and the ION7550 and ION7650 offer two possible loss calculation methods. One must be selected when Loss Compensation is enabled:

- Test Sheet (Method 1)
- %Loss Constants (Method 2)

Both methods are based on the same calculations and produce identical results if the correct input parameters are programmed into the meter. The difference between these methods is in the type of parameters required to perform the loss calculations.

To simplify verification in Method 2, the user is required to calculate the parameters in advance.

CAUTION

Due to the variation in installations, advanced knowledge of power systems and connection methods is required before transformer loss compensation can be properly implemented. Data parameters should only be programmed by qualified personnel that have appropriate training and experience with Transformer Loss Compensation calculations.

SUPPORTED TLC CONFIGURATIONS

Power Transformer Wiring (metered side)	ION8300/ION8400/ ION8500 Volts Mode	ION7550, ION7650 Meters Volts Mode
3-Wire Closed Delta	35S	Delta
4-Wire WYE (3 element)	9S	4-Wire WYE
4-Wire WYE (2½ element)*	36S	3-Wire WYE
3-Wire WYE	9S	3-Wire WYE

* V2 values are only accurate for balanced loads.

When compensation is enabled, the meter calculates transformer and line loss based on a set of input parameters. These parameters determine whether the meter adds or subtracts the losses from the measured power. Compensation can be enabled using either the Vista component of ION Enterprise or ION Setup.

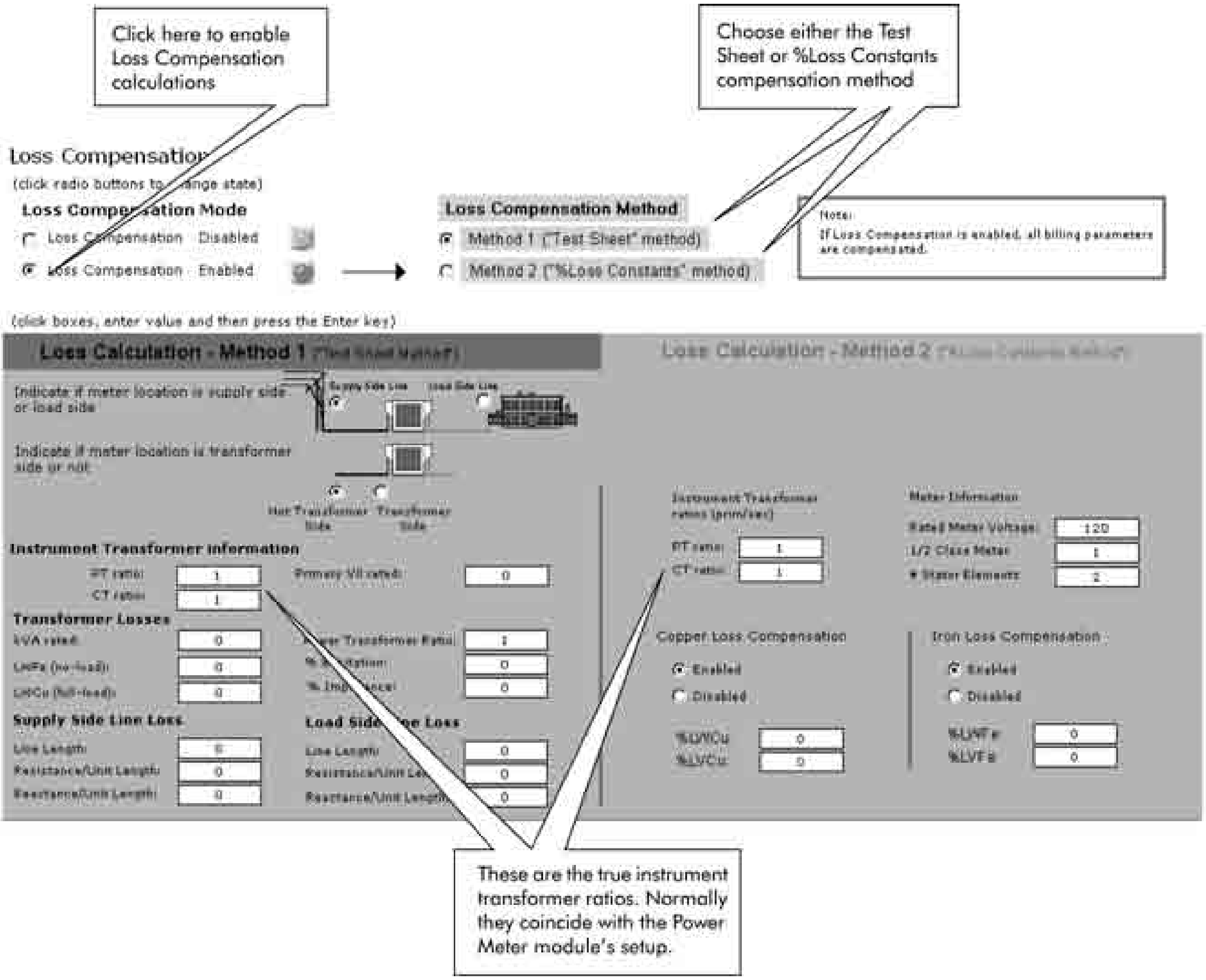
CONFIGURING LOSS COMPENSATION USING VISTA

Click the Loss Compensation button in the Revenue screen to access the Loss

Compensation screen:

1. Launch Vista.
2. In the User Diagram screen that appears, click the Revenue button.

3. Click the Loss Compensation button. The following window appears (the screen for ION8300/ION8400/ION8500 Loss Compensation is shown below):



Click here to enable Loss Compensation calculations

Choose either the Test Sheet or %Loss Constants compensation method

Loss Compensation
(click radio buttons to change state)

Loss Compensation Mode
○ Loss Compensation Disabled
● Loss Compensation Enabled

Loss Compensation Method
● Method 1 ("Test Sheet" method)
○ Method 2 ("%Loss Constants" method)

Note:
If Loss Compensation is enabled, all billing parameters are compensated.

(click boxes, enter value and then press the Enter key)

Loss Calculation - Method 1

Indicate if meter location is supply side or load side: ● Supply Side Line ○ Load Side Line

Indicate if meter location is transformer side or not: ● Not Transformer Side ○ Transformer Side

Instrument Transformer Information
PT ratio: 1
CT ratio: 1
Primary VII rated: 0

Transformer Losses
kVA rated: 0
LWFe (no-load): 0
LWCu (full-load): 0
Power Transformer Ratio: 1
% Excitation: 0
% Impedance: 0

Supply Side Line Loss
Line Length: 0
Resistance/Unit Length: 0
Reactance/Unit Length: 0

Load Side Line Loss
Line Length: 0
Resistance/Unit Length: 0
Reactance/Unit Length: 0

Loss Calculation - Method 2

Instrument Transformer ratios (prim/sec)
PT ratio: 1
CT ratio: 1

Meter Information
Rated Meter Voltage: 120
1/2 Class Meter: 1
Stator Elements: 2

Copper Loss Compensation
● Enabled
○ Disabled
%LWCu: 0
%LVCu: 0

Iron Loss Compensation
● Enabled
○ Disabled
%LWFe: 0
%LVFe: 0

These are the true instrument transformer ratios. Normally they coincide with the Power Meter module's setup.

4. Configure your values as required.

For a detailed explanation of values and their calculations, see "Loss Compensation Input Parameters".

CONFIGURING LOSS COMPENSATION USING ION SETUP

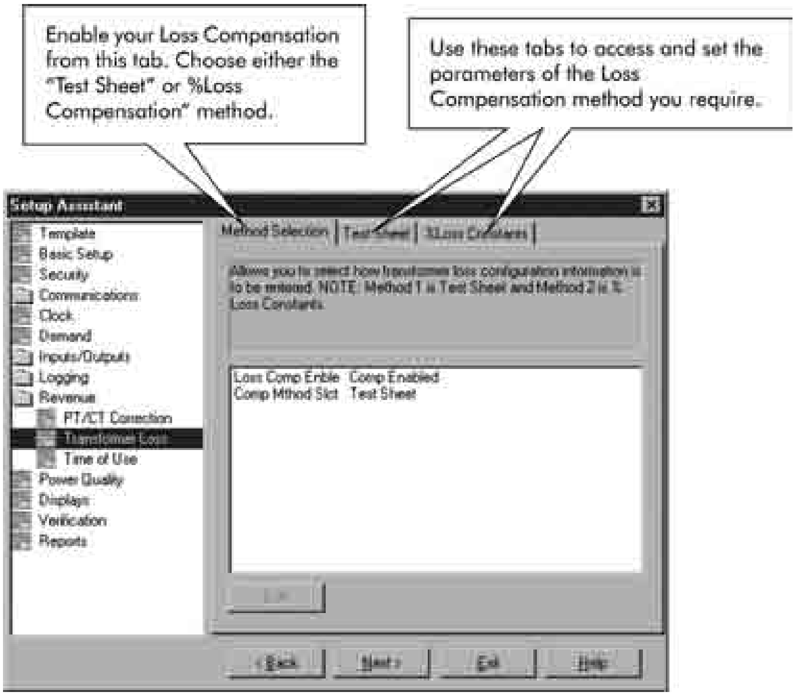
1. Log on to ION Setup and connect to the appropriate meter.

2. Double-click the Setup Assistant and navigate to the Revenue > Transformer

Loss screen.

3. Click the Method Selection tab to select how Transformer Loss information is entered.

4. Click either the %Loss Constant or the Test Sheet tabs (depending on your selected calculation method) and configure the value settings.



Enable your Loss Compensation from this tab. Choose either the "Test Sheet" or %Loss Compensation" method.

Use these tabs to access and set the parameters of the Loss Compensation method you require.

Allows you to select how transformer loss configuration information is to be entered. NOTE: Method 1 is Test Sheet and Method 2 is % Loss Constants.

Loss Comp Enble Comp Enabled
Comp Mthod Slct Test Sheet

SINGLE-PHASE TESTING IN ION SETUP

You can also test Transformer Line Loss with a single-phase source. To test with single-phase in ION Setup:

1. Log on to ION Setup and connect to the appropriate meter.

2. Double-click the Setup Assistant and select the Verification screen.

3. Select Test Mode and click Display.

A window appears informing you the meter is now in test mode.

4. Select Volts, Amps and Power.

5. Click Loss Mode and select Single Phase.

6. In the Setup Assistant screen, navigate to Revenue > Transformer Loss and set your loss parameters.

LOSS COMPENSATION INPUT PARAMETERS

Depending on the method chosen for Transformer Loss Compensation, the meter requires specific data parameters to be programmed into the meter. The data for each method is listed below. All parameters can be programmed into the meter using ION software.

The following is a detailed description of the input parameters required by both methods.

INPUT PARAMETERS FOR METHOD 1: “TEST SHEET”

Line losses and transformer losses are calculated separately and applied to the measured power, energy and demand quantities based on the location of the meter with regards to the power transformer, supply-side line and load-side line.

All parameters required for this method can be obtained from the transformer and line manufacturer.

The same unit of length (meter or foot) must be used for all parameters.

Line loss calculation parameters:

$$\text{Power Transformer Ratio} = \left(\frac{\text{Voltage on supply side}}{\text{Voltage on load side}}\right)$$

The value of Power Transformer Ratio will be less than 1 for generation applications. If there is no power transformer used, set this value to 1.

For the line on the supply side (SY) of the transformer:

$$\text{Resistance/Unit length} \left(\frac{r}{l_{sy}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Reactance/Unit length} \left(\frac{x}{l_{sy}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Line length}_{sy} \text{ in } [\text{m}] \text{ or } [\text{ft}]$$

For the line on the load side (LD) of the transformer:

$$\text{Resistance/Unit length} \left(\frac{r}{l_{ld}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Reactance/Unit length} \left(\frac{x}{l_{ld}}\right) \text{ in } [\Omega/\text{m}] \text{ or } [\Omega/\text{ft}]$$

$$\text{Line length}_{ld} \text{ in } [\text{m}] \text{ or } [\text{ft}]$$

ION meters then calculate the line losses as:

$$\text{LLW[W]} = I^2_{avg} \times \frac{r}{l} \times \text{Line Length} \times 3 \tag{13a}$$

$$\text{LLV[VAR]} = I^2_{avg} \times \frac{x}{l} \times \text{Line Length} \times 3 \tag{13b}$$

These calculations are performed separately for the supply side part of the line and the load side part.

TRANSFORMER LOSS CALCULATION PARAMETERS:

When this method is selected, then the following power transformer and line data is programmed into the meter:

- Rated power transformer voltage (VLL on metered-side of Power Transformer)
- Rated power transformer kVA
- Power transformer ratio (Voltage on Supply Side/Voltage on Load Side)
- No-load iron test loss watts
- Full-load copper test loss watts
- Percent exciting current
- Percent impedance
- Line length of load-side and supply-side line
- Resistance and reactance per unit length for both lines
- Instrument transformer ratios (VTR, CTR)
- Information about the location of the meter with regards to the power transformer, supply-side line and load-side line

The iron and copper losses are then calculated using equations 7 to 12, based on the measured load current and voltage.

LINE LOSS AND TRANSFORMER LOSS COMPENSATION

Once the losses are calculated, you can add or subtract losses from the measured active and reactive power values in real-time.

Metering Location Parameters:

- MP Definition 1

This parameter indicates if the power monitor (metering point) is installed on the supply side of the transformer or the load side.

- MP Definition 2

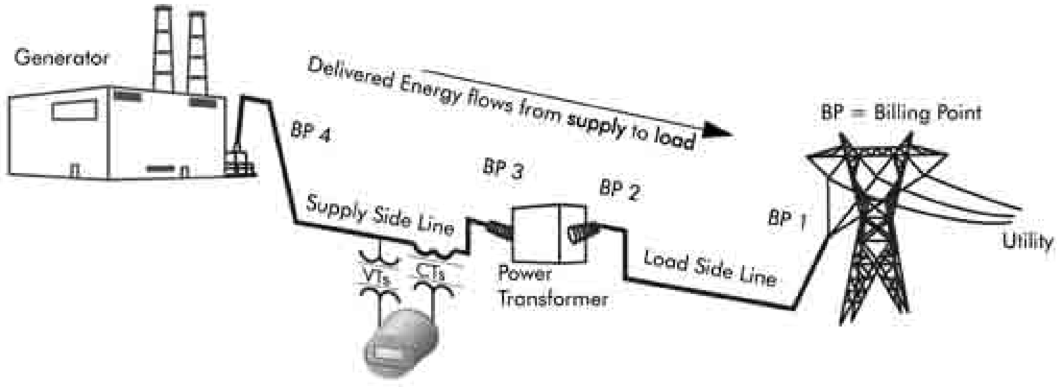
This parameter indicates if the power monitor (metering point) is installed on the transformer end of the line or on the far end.

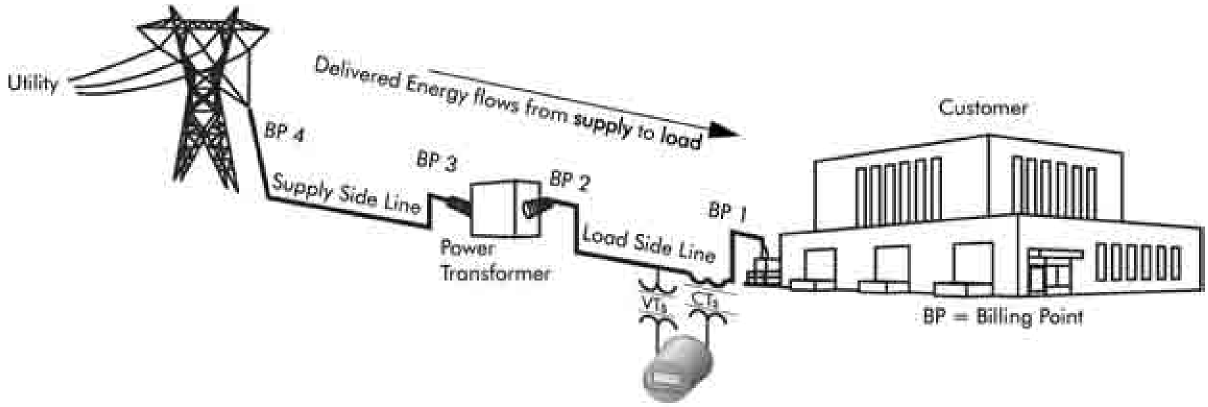
USE CASES: METERING POINT & BILLING POINT LOCATIONS

The following diagram outlines the possible locations of the billing points (BP) and metering points.

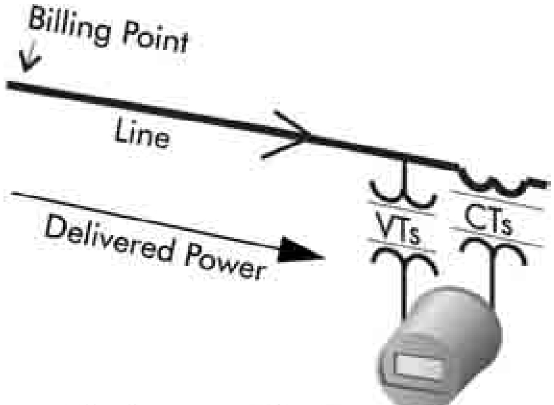
Some scenarios involve energy delivered from generator to the Utility, and others from the Utility to the customer.

The following examples show how the location of the power monitor and the billing point affect the calculation of compensated power values.





LINE LOSS ONLY



Line Losses **added to** power and energy quantities.

Adding Line Losses:

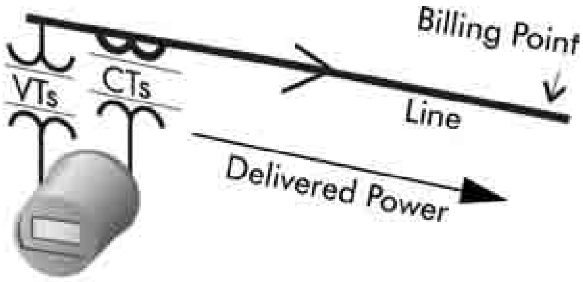
Line losses are added to the delivered power and energy quantities. Set the loss calculation parameters in the meter as follows:

Parameter		**Setting**
MP Definition 1	=	Load Side
MP Definition 2	=	Not Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
r/l_{ld}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{ld}	=	enter reactance in [Ω/m] or [Ω/ft]
Line length$_{ld}$	=	enter line length in [m] or [ft]

Leave all other parameters at their default settings.

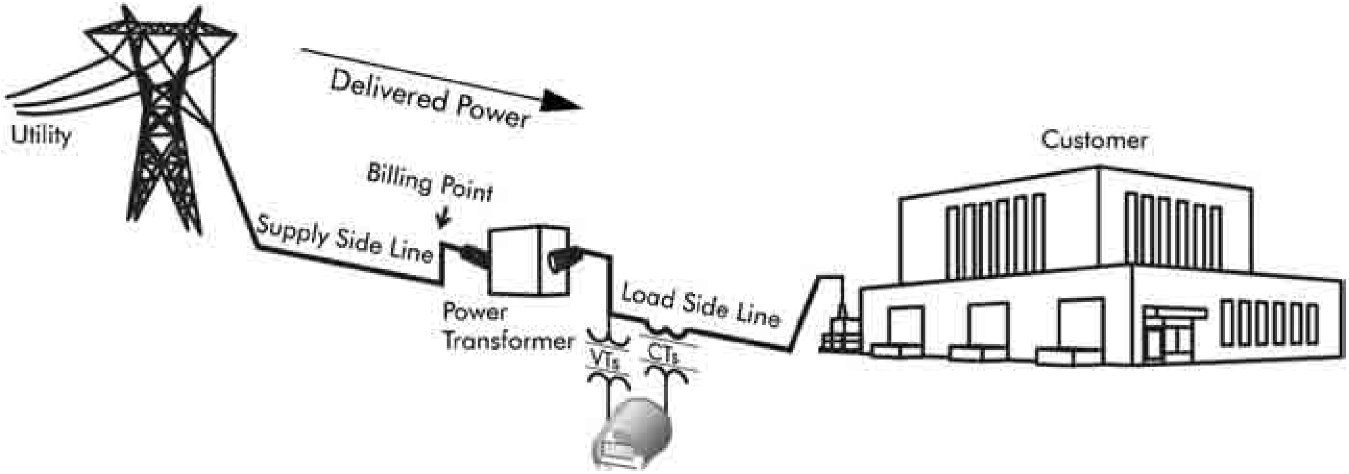
Subtracting Line Losses:

Change MP Definition 2 to “Transformer Side” so that the line losses are subtracted from the power and energy quantities.



Line Losses **subtracted from** power and energy quantities.

TRANSFORMER LOSS ONLY



Adding Transformer Losses:

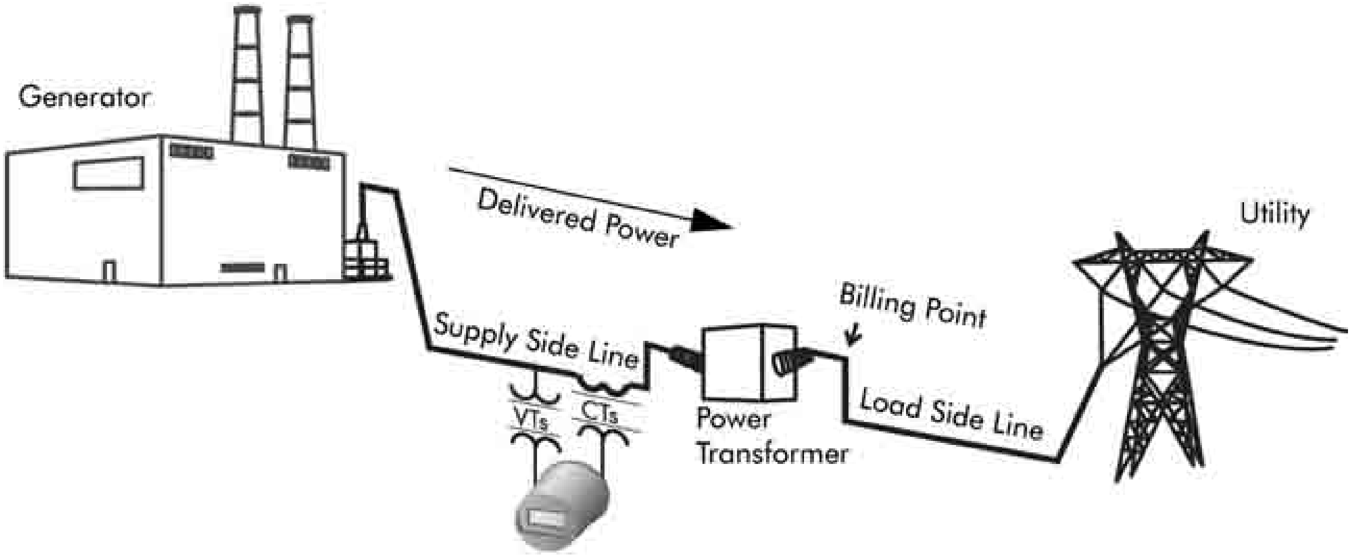
Transformer losses are added to power and energy quantities. The loss calculation parameters in the meter should be set as follows:

Parameter		Setting
MP Definition 1	=	Load Side
MP Definition 2	=	Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
Vll_{rated}	=	enter Transformer data
$LWFe_{test}$	=	enter Transformer data
$LWCu_{test}$	=	enter Transformer data
%Excitation	=	enter Transformer data
%Impedance	=	enter Transformer data

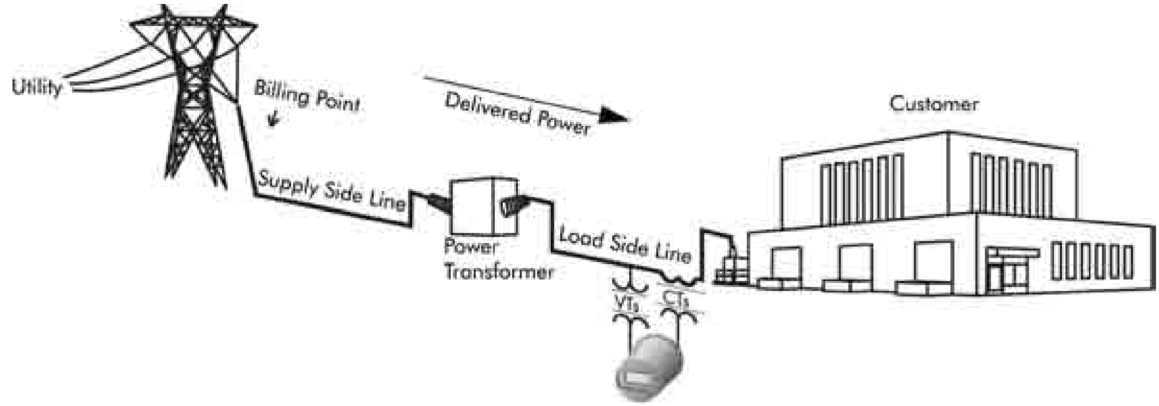
Leave all other parameters at their default settings.

Subtracting Transformer Losses:

Change MP Definition 1 to “Supply Side” so that transformer losses are subtracted from the power and energy quantities.



LINE LOSS AND TRANSFORMER LOSS



Adding Line & Transformer Losses:

The transformer and line losses are added to measured power and energy values. Set the meter's loss calculation parameters to:

Parameter		**Setting**
MP Definition 1	=	Load Side
MP Definition 2	=	Not Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
Power Transformer Ratio	=	(Voltage on Supply Side/Voltage on Load Side)
Vll_{rated}	=	enter Transformer data
$LWFe_{test}$	=	enter Transformer data
$LWCu_{test}$	=	enter Transformer data
%Excitation	=	enter Transformer data
%Impedance	=	enter Transformer data
r/l_{sy}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{sy}	=	enter reactance in [Ω/m] or [Ω/ft]
Line $length_{sy}$	=	enter line length in [m] or [ft]
r/l_{LD}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{LD}	=	enter reactance in [Ω/m] or [Ω/ft]
Line $length_{ld}$	=	enter line length in [m] or [ft]

Leave all other parameters at their default settings. To ignore load-side or supply-side line losses, set the corresponding length to zero.

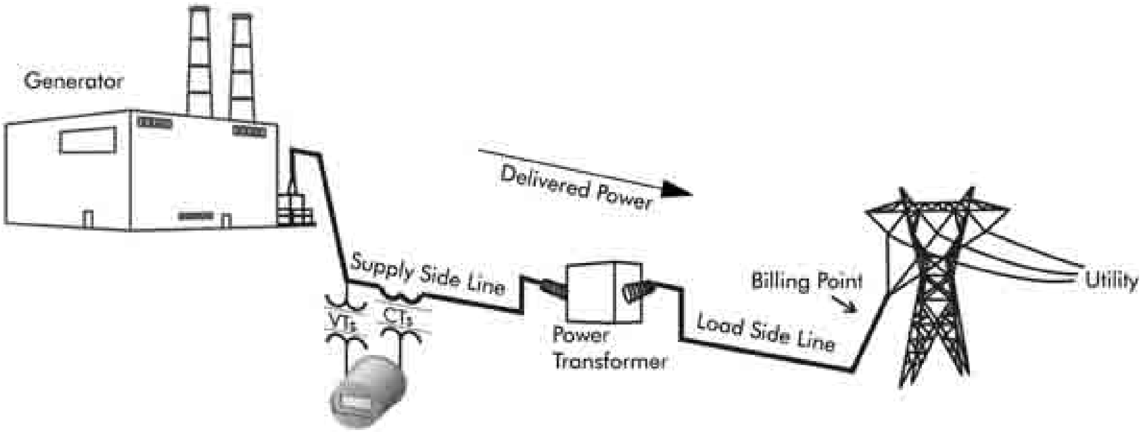
Subtracting Line & Transformer Losses:

Change the MP Definition 1 to "Supply Side" (see list of Parameters and Settings on the previous page) so that losses are subtracted from power and energy quantities.

INPUT PARAMETERS FOR METHOD 2: "% LOSS CONSTANTS"

When using this method in ION meters with a delta connection, compute the %Loss values with respect to the single-phase system kVA. To confirm TLC operation, verify that the amount of compensated watts matches the expected.

In this method, line loss and transformer loss calculation parameters are computed manually or through a third party program into four (4) loss constants. These values are then programmed into the meter. The meter uses these constants to calculate the losses and perform the compensation.



This method allows you to enable or disable iron and copper loss calculations separately. When this method is selected, the following data must be programmed into the meter:

- Percent iron Watt loss constant (%LWFe)*
- Percent copper Watt loss constant (%LWCu)*
- Percent iron VAR loss constant (%LVFe)*
- Percent copper VAR loss constant (%LVCu)*
- Instrument transformer ratios (VTR, CTR)
- Rated meter voltage (VMrated)
- 1/2 Class meter current (1/2IMrated)
- Number of stator elements (2 for Delta connections, 3 for WYE)

* If you want the losses to be subtracted from Delivered Energy, enter negative values for the percent loss constants.

The field "# stator elements" indicate the number of metering elements to configure for transformer loss compensation:

ION8300/ ION8400/ ION8500 Volts Mode	ION7550, ION7650 Meters Volts Mode	Number of stator elements
35S	Delta	2
9S, 36S	4-Wire WYE 3-Wire WYE	3

These are the values you program into the ION meter. To properly implement Transformer Loss Calculations using Method 2, you must calculate constants using the following relationships. See "Appendix A: Glossary" and ensure you fully understand the terms used below. Failure to calculate exactly as outlined below will result in incorrect readings.

PERCENT-LOSS CONSTANT CALCULATIONS

Both L-L, or both L-N

$$\%LWFe = \frac{LWFe_{TXtest} \times \left[\frac{V_{Mrated} \times VTR}{V_{TXtest}}\right]^2}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

Both L-L, or both L-N

$$\%LVFe = \frac{LVFe_{TXtest} \times \left[\frac{V_{Mrated} \times VTR}{V_{TXtest}}\right]^4}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$\%LWCu = \frac{LWCu_{TXtest} \times \left[\frac{\frac{1}{2}I_{Mclass} \times CTR}{I_{TXtest}}\right]^2 + LLW_{Mclass}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$= \frac{(\frac{1}{2}I_{Mclass} \times CTR)^2 \times \text{Total System Resistance}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

System Resistance and System Reactance include both transformer and line impedance.

$$\%LVCu = \frac{LVCu_{TXtest} \times \left[\frac{\frac{1}{2}I_{Mclass} \times CTR}{I_{TXtest}}\right]^2 + LLW_{Mclass}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$= \frac{(\frac{1}{2}I_{Mclass} \times CTR)^2 \times \text{Total System Reactance}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

LOSS CALCULATIONS IN ION METERS

ION meters use these constants to calculate the losses as follows:

$$LWFe = \frac{\%LWFe}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^2 \tag{19}$$

$$LVFe = \frac{\%LVFe}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^4 \tag{20}$$

$$LWCu = \frac{\%LWCu}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{I_{actual}}{\frac{1}{2}I_{Mclass}}\right]^2 \tag{21}$$

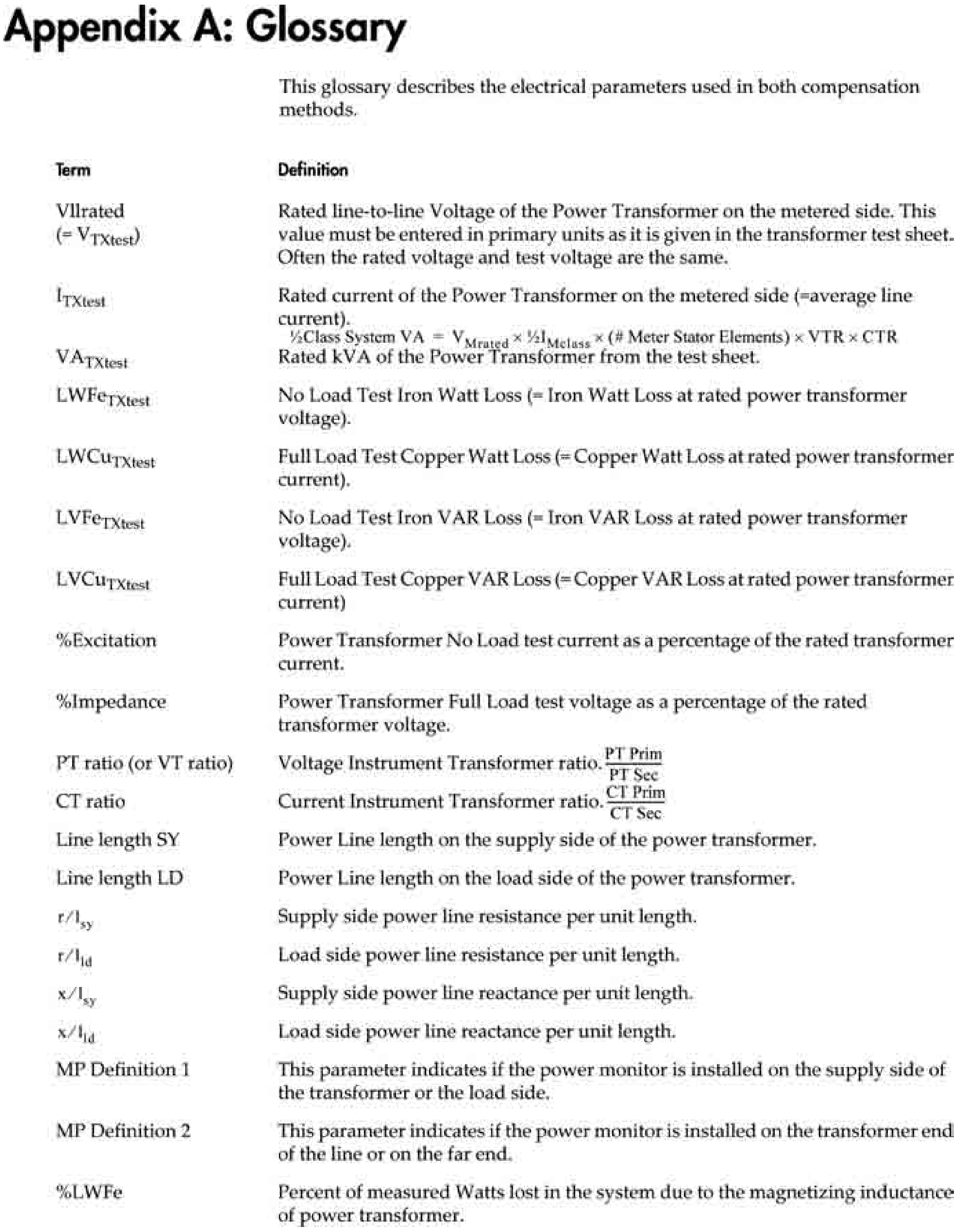
$$LVCu = \frac{\%LVCu}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{I_{actual}}{\frac{1}{2}I_{Mclass}}\right]^2 \tag{22}$$

Important Note for Percent-Loss Loss Equations (14-17) and Power Loss Equations (19 - 22)

Because the meter's first step in its "Loss Calculations" computation is to cancel out the "1/2 Class System VA" value, the "1/2 Class System VA" value that is used in the "Percent-Loss Constant Calculations" on page 16 must be calculated exactly as outlined in equation 18 (above). If the "1/2 Class System VA" value is not what the meter expects, the two terms will not fully cancel out. This will result in incorrect loss calculations.

APPENDIX A: GLOSSARY

This glossary describes the electrical parameters used in both compensation methods.



Appendix A: Glossary

This glossary describes the electrical parameters used in both compensation methods.

Term	Definition
Vllrated (= V_{TXtest})	Rated line-to-line Voltage of the Power Transformer on the metered side. This value must be entered in primary units as it is given in the transformer test sheet. Often the rated voltage and test voltage are the same.
I_{TXtest}	Rated current of the Power Transformer on the metered side (=average line current). $\frac{1}{2}\text{Class System VA} = V_{Mrated} \times \frac{1}{2} I_{Mclass} \times (\text{\# Meter Stator Elements}) \times VTR \times CTR$
VA_{TXtest}	Rated kVA of the Power Transformer from the test sheet.
$LWFe_{TXtest}$	No Load Test Iron Watt Loss (= Iron Watt Loss at rated power transformer voltage).
$LWCu_{TXtest}$	Full Load Test Copper Watt Loss (= Copper Watt Loss at rated power transformer current).
$LVFe_{TXtest}$	No Load Test Iron VAR Loss (= Iron VAR Loss at rated power transformer voltage).
$LVCu_{TXtest}$	Full Load Test Copper VAR Loss (= Copper VAR Loss at rated power transformer current)
%Excitation	Power Transformer No Load test current as a percentage of the rated transformer current.
%Impedance	Power Transformer Full Load test voltage as a percentage of the rated transformer voltage.
PT ratio (or VT ratio)	Voltage Instrument Transformer ratio. $\frac{\text{PT Prim}}{\text{PT Sec}}$
CT ratio	Current Instrument Transformer ratio. $\frac{\text{CT Prim}}{\text{CT Sec}}$
Line length SY	Power Line length on the supply side of the power transformer.
Line length LD	Power Line length on the load side of the power transformer.
r/l_{sy}	Supply side power line resistance per unit length.
r/l_{ld}	Load side power line resistance per unit length.
x/l_{sy}	Supply side power line reactance per unit length.
x/l_{ld}	Load side power line reactance per unit length.
MP Definition 1	This parameter indicates if the power monitor is installed on the supply side of the transformer or the load side.
MP Definition 2	This parameter indicates if the power monitor is installed on the transformer end of the line or on the far end.
%LWFe	Percent of measured Watts lost in the system due to the magnetizing inductance of power transformer.

%LWCu	Percent of measured Watts lost in the system due to impedance in lines and windings.
%LVFe	Percent of measured VARs lost in the system due to the magnetizing inductance of power transformer.
%LVCu	Percent of measured VARs lost in the system due to impedance in lines and windings.
System Resistance	Sum of power transformer and line resistance on all phases.
System Reactance	Sum of power transformer and line reactance on all phases.
V_{Mrated} (Rated Meter Voltage)	Nominal meter input voltage. This is the value used in the calculation of the Percent Iron Loss constants. The rated meter voltage will be a line-to-neutral voltage for 3 element metering and a line-to-line voltage for 2 element metering. The Rated Meter Voltage must be entered in meter units (= unscaled).
$½I_{Mrated}$ (½ Class Meter Current)	Half the value of the certified meter class current. This value has to match the value used in the calculation of the Percent Loss Constants.
# of Stator Elements	Number of measuring elements used in the meter. This number is determined by the form factor of the power monitor. 9S meters for example in a 4 wire application use 3 elements. 35S meters used for 3 wire applications use 2 elements.
LLV_{Mclass}	Line loss VARs at the meter's ½ class current.
LLW_{Mclass}	Line Loss Watts at the meter's ½ class current.

APPENDIX B: LOSS COMPENSATION FRAMEWORKS

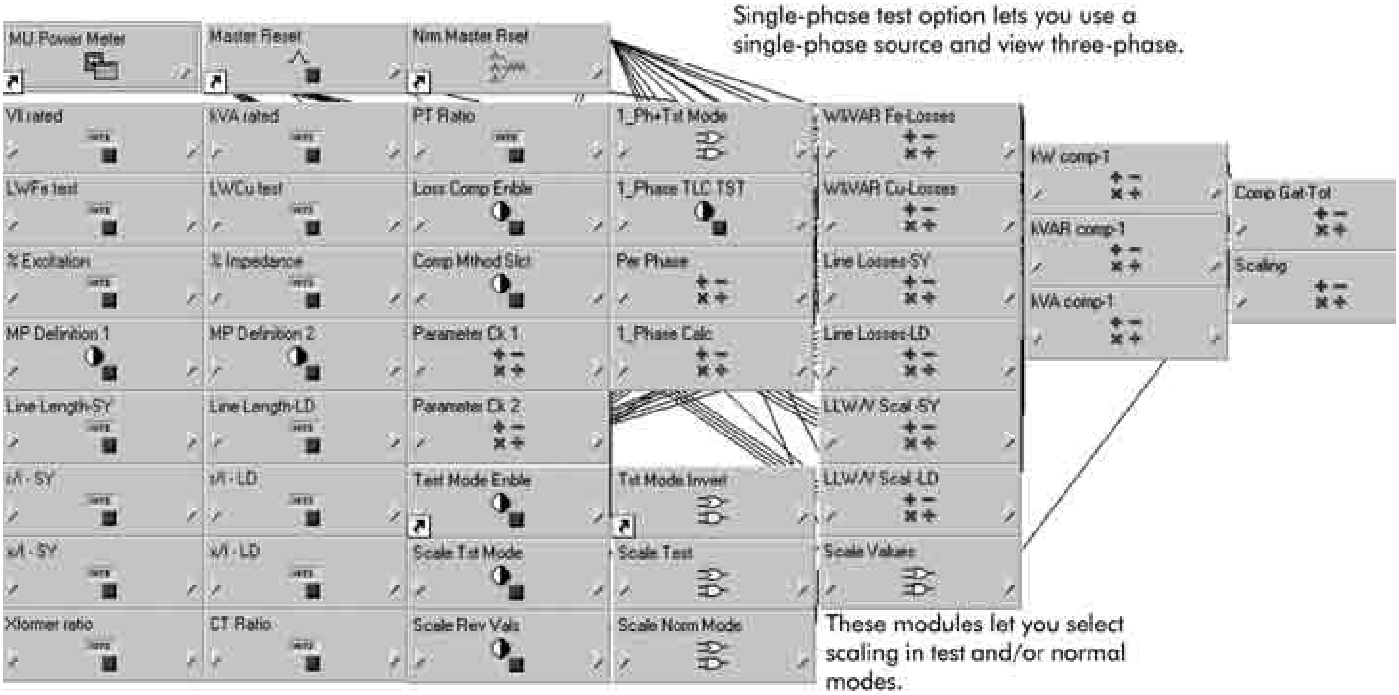
METHOD 1: "TEST SHEET"

The following screen capture shows the view of this framework in Designer:

On the left side are the External Numeric and External Boolean modules that are used to enter transformer and line data for the loss calculations. The Arithmetic modules perform the actual calculations.

Before the transformer and line data is passed into the Arithmetic modules that perform the loss calculations, the data is checked for invalid entries such as negative numbers to ensure that the outputs of the Arithmetic loss modules will always be available.

A division by "0" or a negative number in a square root



Single-phase test option lets you use a single-phase source and view three-phase.

These modules let you select scaling in test and/or normal modes.

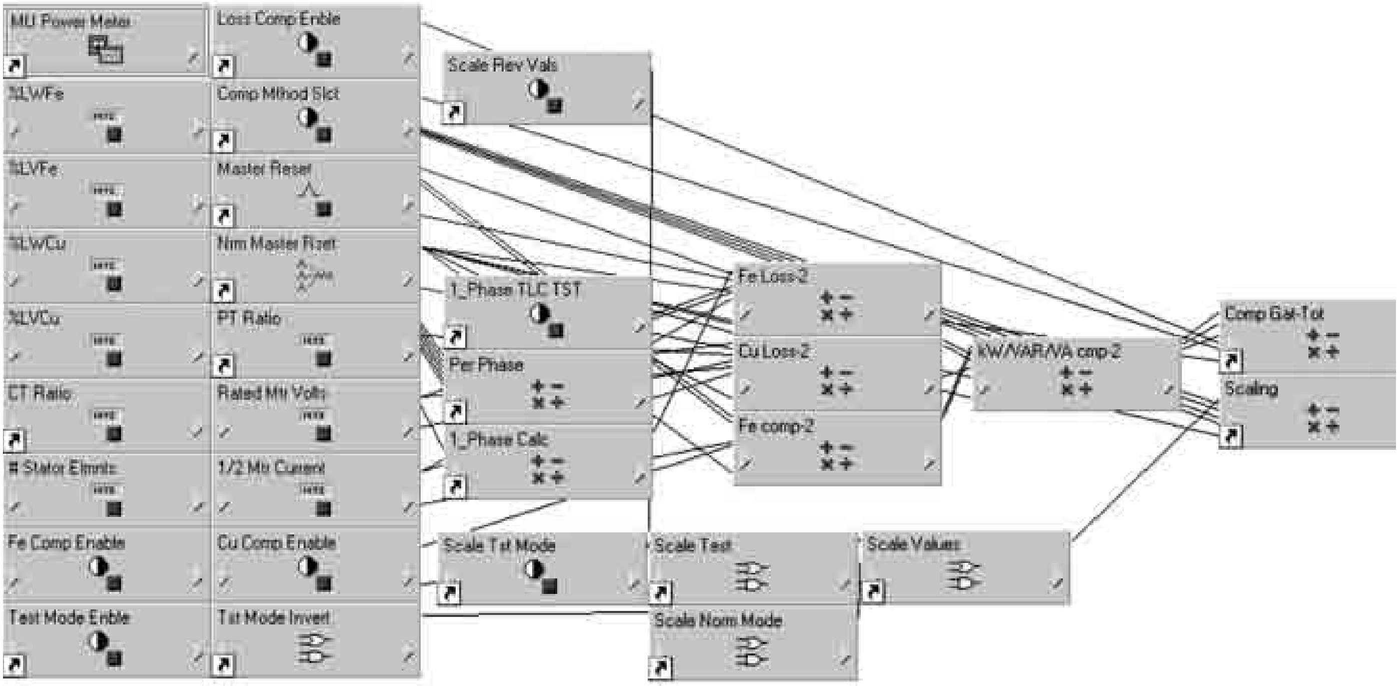
would cause a “Not available” output on the Arithmetic modules.

Line loss totals must be scaled prior to final energy scaling since the line losses are I2R (measured in Watts). Note that there is no voltage component in this Watts measurement. Scaling line loss prior to final power scaling provides CT2 as a multiplier for line losses:

$$
\begin{aligned}
\text{Line Loss} &= [\text{Losses in MU}] \times [\text{PTR} \times \text{CTR}] \\
&= \left[\frac{(I_{sec} \times \text{CTR})^2 \times R}{\text{PTR} \times \text{CTR}}\right] \times (\text{PTR} \times \text{CTR}) \\
&= \left[(I_{sec})^2 \times R \times \frac{\text{CTR}}{\text{PTR}}\right] \times (\text{PTR} \times \text{CTR})
\end{aligned}
$$

METHOD 2: “%LOSS CONSTANTS”

The following screen capture shows the view of the framework in Designer:



On the left side are the External Numeric and External Boolean modules that are used to enter transformer and line data for the loss calculations. The Arithmetic modules perform the actual calculations.

SINGLE-PHASE TESTING

You can connect a single-phase source voltage in parallel and the current in series to simulate a three-phase source. Some ION meters automatically adjust the voltage in this test situation when the meter is in Test Mode and the single-phase option is selected.

NEW MEASUREMENT METHODS TO CHARACTERIZE TRANSFORMER CORE LOSS AND COPPER LOSS IN HIGH FREQUENCY SWITCHING MODE POWER SUPPLIES

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Department of Electrical and Computer Engineering

I. INTRODUCTION

Measurement methods are widely used for transformer core loss and copper loss characterization due to the potential for higher accuracy in comparison to simple conventional analytical methods. Unfortunately, no measurement methods are available that can measure the transformer core loss and copper loss under the actual operation conditions in switching mode power supplies (SMPS).

The existing measurement methods determine transformer core loss under sinusoidal excitation using an impedance or network analyzer [1],[2]. However, the pulse width modulation (PWM) waveforms in SMPS are not sinusoidal, but are rectangular. In addition, converters such as the flyback and asymmetrical half-bridge (AHB) contain a DC bias in the magnetizing current, but these methods cannot account for the DC bias. Furthermore, due to the highly non-linear nature of the B-H property of ferrite materials, Fourier analysis can yield completely erroneous results. Therefore, the impedance or network analyzer method cannot be applied to accurately determine the core loss in high frequency switching converters.

In [3] and [4], two measurement setups were designed to experimentally determine transformer core loss. In [3], sine waveforms were used to obtain the core loss curves for the ferrite materials. In addition, no core loss results for switching converters are provided. In [4], a method is proposed to measure transformer core loss for a SMPS using a waveform generator and a power amplifier.

Unfortunately, using these techniques, the core loss cannot be determined if the transformer under test operates with a DC bias in the magnetizing current. It is also noted that an error analysis of the proposed methods was not conducted and the corresponding measurement accuracy was not provided. Therefore, if these techniques are used, the user cannot interpret the accuracy of their results. To overcome the limitations of the existing methods, an improved method to determine transformer core loss in high frequency SMPS is proposed, which is suitable for core loss measurement under PWM excitation, with or without a DC bias.

In [5], a method is proposed to calculate transformer copper loss by measuring winding AC resistance for each harmonic in the PWM current. The method uses sinusoidal waveforms in the measurement and not the rectangular PWM waveforms under the transformer operating conditions. The drawback to this technique is that it does not replicate the field pattern within the transformer. In addition, the measurements are time-consuming. Another disadvantage of this method is that the results only provide information about winding self-resistance. When both the primary and secondary windings have current flowing through them at the same time, the field interaction due to proximity effect induces a mutual resistance between them, which can significantly reduce the total transformer copper loss. Therefore, an "in-component" measurement scheme for transformer AC winding resistance is proposed. The method uses the PWM current waveforms, so, the mutual resistance between windings is inherently included, which yields increased accuracy.

In section II, the core loss measurement method is proposed. In section III, the proposed copper loss measurement method is presented. The experimental verification is provided in section IV. In section V, a detailed error analysis is presented for each method. The conclusions are presented in section VI.

II. PROPOSED CORE LOSS MEASUREMENT METHOD

The proposed transformer core loss measurement test setup is shown in Figure 1. With the secondary side opencircuit, the averaged core loss PCore over one switching period T can be determined from the primary voltage vpri(t) and the magnetizing current iM(t) using (1).

$$P_{Core} = \frac{1}{T}\int_0^T v_{pri}(t)\cdot i_M(t)dt \qquad (1)$$

Due to the leakage inductance and resistance associated with the primary winding, the winding voltage cannot be measured directly. However, the secondary side voltage vsec(t) can be measured and reflected back to the primary side using the turns ratio. Since the secondary winding is open circuit, the only primary terminal current is the magnetizing current, which is sensed using a resistor RSense.

By measuring the secondary voltage and the voltage across a sensing resistor, we can obtain the averaged core loss over one switching period T using (2).

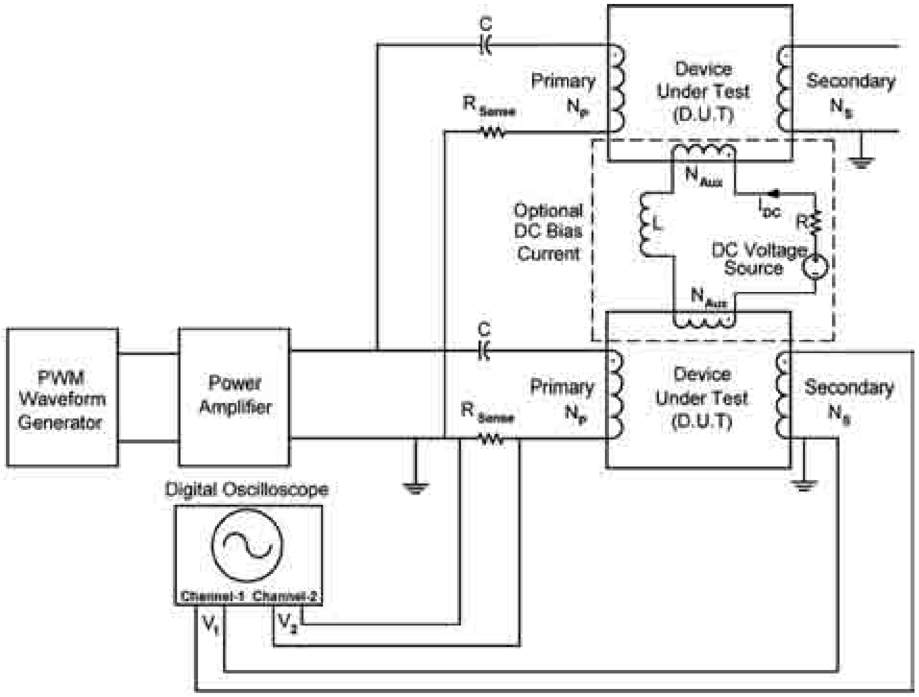


Figure 1 Proposed core loss measurement test setup

Using a digital oscilloscope with channel math capabilities, (2) can be evaluated directly using the oscilloscope. In (2), NP and Ns are the primary and secondary winding turns; v1i and v2i are the ith sample of the measured voltage values of the secondary side and current sensing resistor; N is the number of the samples in one switching period.

$$P_{Core} = \frac{N_p}{N_s} \frac{1}{N} \sum_{i=1}^{N} v_{1i} \cdot \frac{v_{2i}}{R_{sense}} \qquad (2)$$

The practical implementation issues of the measurement setup are explained as follows:

1) POWER SOURCE

A PWM waveform generator (function generator) and an RF power amplifier (3MHz bandwidth) are used to provide the PWM voltage source to the transformer.

2) CURRENT SENSING DEVICE

A low-inductive metal film resistor is used to measure the magnetizing current. In order to minimize the distortion on the waveform and at the same time to reduce the phaseshift error, ten 10Ω±1% metal film resistors were connected in parallel. The impedance characteristic of the resistor combination is flat up to 5MHz.

3) DC BIAS CURRENT

An optional auxiliary winding can be introduced to provide the equivalent DC magnetomotive force to the core for transformers that operate with a DC bias component in the magnetizing current. A 2mH inductor was connected in the auxiliary circuit to reduce the high frequency AC ripple.

In addition, two auxiliary windings with the same number of turns were connected with opposite polarities to eliminate the AC voltage from the primary winding. The second auxiliary winding is connected into the same transformer as the one under test.

In order to ensure the measurement of the transformer core loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

A. CALIBRATION OF THE WINDING TURNS RATIO

The proposed core loss measurement method has two ports.

Due to the non-ideal magnetic coupling, parasitic air flux and the winding terminations, the primary and secondary winding terminal voltage ratio can vary slightly from the designed turns ratio. In order to minimize this error, the winding turns ratio should be calibrated. For the turns ratio calibration, a sinusoidal wave can be used to simplify the process. The turns ratio result can be applied to the rectangular PWM waveforms under test. The terminal voltages (peak or peak-to-peak value) of the primary and secondary windings are measured and the actual turns ratio is calculated using (3), which is then used in (2). The calibration should be conducted over a range of frequencies.

$$N_{Turns-Ratio} = V_{Pri} / V_{Sec} \qquad (3)$$

B. CURRENT SENSING RESISTANCE CALIBRATION

Some error will be introduced into the core loss measurement due to the tolerance and the associated inductance of the current sense resistor. A good approach is to calibrate the resistor's frequency response using the impedance analyzer to ensure its frequency response remains flat for several harmonics of the switching frequency.

C. AVERAGING DATA

Averaging should be adopted for the data processing.

The core loss for each operating condition should be tested ten times and then the values should be averaged.

III. PROPOSED COPPER LOSS MEASUREMENT METHOD

The objective of transformer copper loss measurement is to obtain an equivalent AC resistance for each winding under the actual operating conditions. To proceed, it is important to clarify the following two concepts:

1) We need to define the current wave shape used in the measurement under the SMPS operating conditions. By analyzing the SMPS circuits, the currents flowing through the windings can usually be well approximated as a rectangular wave shape (unipolar or bipolar) of the corresponding duty ratio by neglecting the small ripple [6].

Therefore, a rectangular PWM current can be used in measuring the transformer copper loss. In this article, a bipolar rectangular PWM waveform is used.

2) A transformer is a multi-winding structure, so, the field interaction between the primary and secondary windings

induces a mutual resistance. Fortunately, we don't need to obtain the mutual resistance information. What we need is an equivalent AC resistance of each winding under the operating condition, which includes the mutual resistance information.

The proposed transformer winding AC resistance measurement scheme is shown in Figure 2. By applying the rectangular PWM voltage in the primary side from the waveform generator and power amplifier, the corresponding magnetic field is established within the transformer and a PWM voltage is induced in the secondary side. If a resistive load is connected on the secondary side, a rectangular current will flow through the load resistor and the secondary winding equivalent AC resistance. The secondary side current iSec can be obtained by measuring the voltage across the load resistor. An auxiliary winding is added to measure the secondary winding terminal voltage. This winding can be easily added externally around the core since it does not carry any current. The two voltages are then measured using a digital oscilloscope. Then the averaged power of the secondary winding PSec and the power of the load resistor PLoad can be calculated over one switching period.

Therefore, the secondary winding equivalent AC resistance can then be calculated using (4), where NSec and NAux are the the secondary and auxiliary winding turns; v1i and v2i are the ith sample of the voltage values; and N is the number of the samples in one switching period.

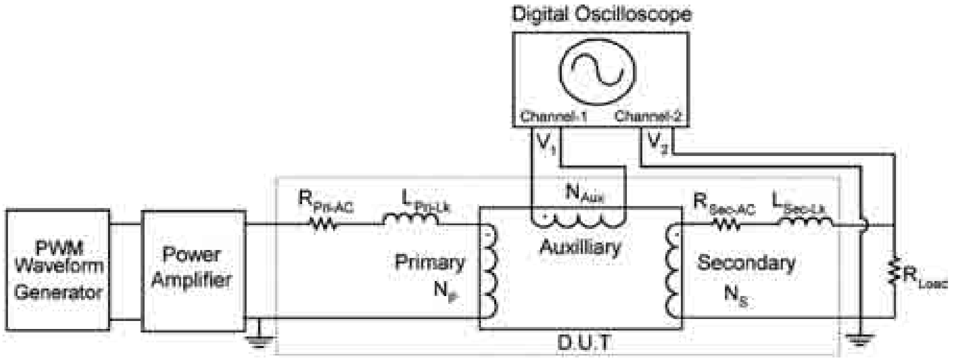


Figure 2 Proposed copper loss measurement test setup

$$R_{Sec-AC}=\frac{P_{Sec}-P_{Load}}{I^2_{SecRMS}}=\frac{\frac{N_{Sec}}{N_{Aux}}\cdot\frac{1}{N}\sum_{i=1}^{N}v_{1i}\cdot\frac{v_{2i}}{R_{Load}}}{\frac{1}{N}\sum_{i=1}^{N}\left(\frac{v_{2i}}{R_{Load}}\right)^2}-R_{Load} \tag{4}$$

By defining the corresponding functions in the digital oscilloscope, the power of the measured winding and the RMS current value over one switching period can be obtained easily and used in the winding resistance calculation. In order to measure the primary winding AC resistance, the secondary winding should be excited.

In order to ensure the measurement of the transformer copper loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

A. CALIBRATION OF THE WINDING TURNS RATIO

In the proposed transformer winding AC resistance measurement method, a third winding is used to obtain the terminal voltage of the measured winding. The actual winding turns ratio between the measured winding and the third winding should be calibrated in order to achieve accurate results. This can be achieved using the procedure outlined in section II.

A. LOAD RESISTANCE CALIBRATION

Since a resistor is used as the load in measuring the winding AC resistance, the resistor's tolerance and frequency response can have a significant impact on measurement results. In order to minimize any error introduced by the resistor, the resistor's frequency response should be measured using an impedance analyzer to obtain an accurate resistance value and phase response.

B. AVERAGING DATA

As in the core loss calculation, the copper loss data in the winding AC resistance measurement should be averaged in order to minimize any random error in the measurements.

IV. MEASUREMENT RESULTS AND VERIFICATION

A high frequency planar transformer was tested to verify the proposed core loss and copper loss methods. In order to verify the loss measurement results, a time-domain Finite Element Analysis solver from ANSOFT was used.

A multi-winding planar transformer was used in an AHB DC/DC converter with unbalanced secondary windings [7].

The converter diagram is shown in Figure 3. The specifications of the converter and the transformer parameters are:

Input: 35-75V, nominal at 48V, output: 5V/25W

Switching frequency: 400kHz

Main winding turns: Np: Ns1: Ns2 = 6:1:3

Core: E18/4/10 planar cores (EE combination)

Winding: 1oz (35micrometres) copper on a 10-layer PCB

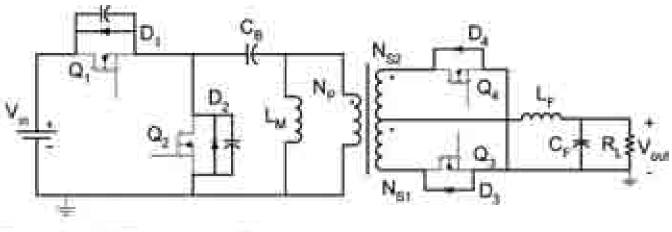


Figure 3 AHB converter diagram

Due to the complementary duty cycle operation and unbalanced secondary windings, the converter operates with a DC bias (IM-DC) in the magnetizing current. It can be calculated using (5).

$$I_{M-DC}=(1-D)I_o\frac{N_{s2}}{N_p}-DI_o\frac{N_{s1}}{N_p} \tag{5}$$

In the transformer design, an air gap of 67 micrometres was added to the core central leg to avoid saturation. The proposed optional circuit to create the DC bias current for the test setup was used in the core loss measurement.

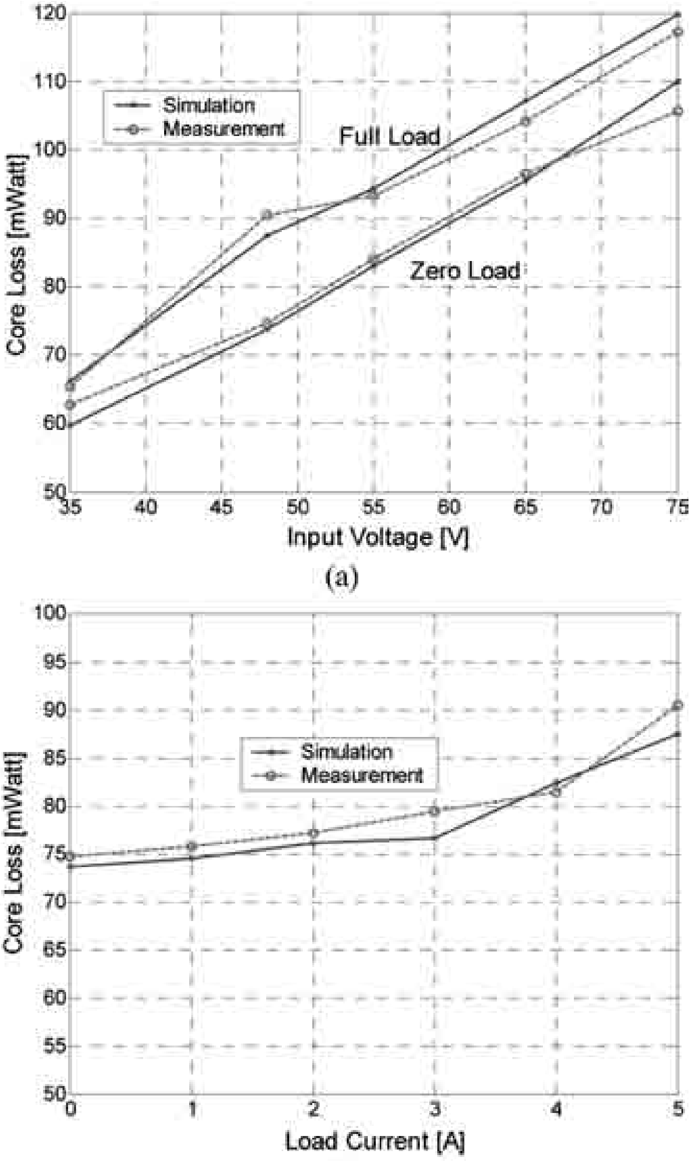
A. CORE LOSS MEASUREMENT RESULTS

The following three operating conditions of the AHB transformer were tested using the proposed method.

1) Vin=35-75V range @ no load
2) Vin=35-75V range @ 5A load
3) Vin=48V @ 0-5A load range

The measurement results and FEA simulation results are provided in Figure 4. In order to illustrate the effect of the DC bias current on the ferrite core loss, Figure 4(a) shows the core loss measurement and simulation results under operating conditions 1) and 2). Figure 4(b) provides the results for operating condition 3). The core losses under the equivalent 400kHz sine waveform and bipolar square waveform (D=50%) with no DC bias current condition were also tested for comparison purposes.

Some typical core loss measurement waveforms under operating condition 1) are shown in Figure 5. The digital oscilloscope math functions implement (2). The results are indicated on the right side of the figure.



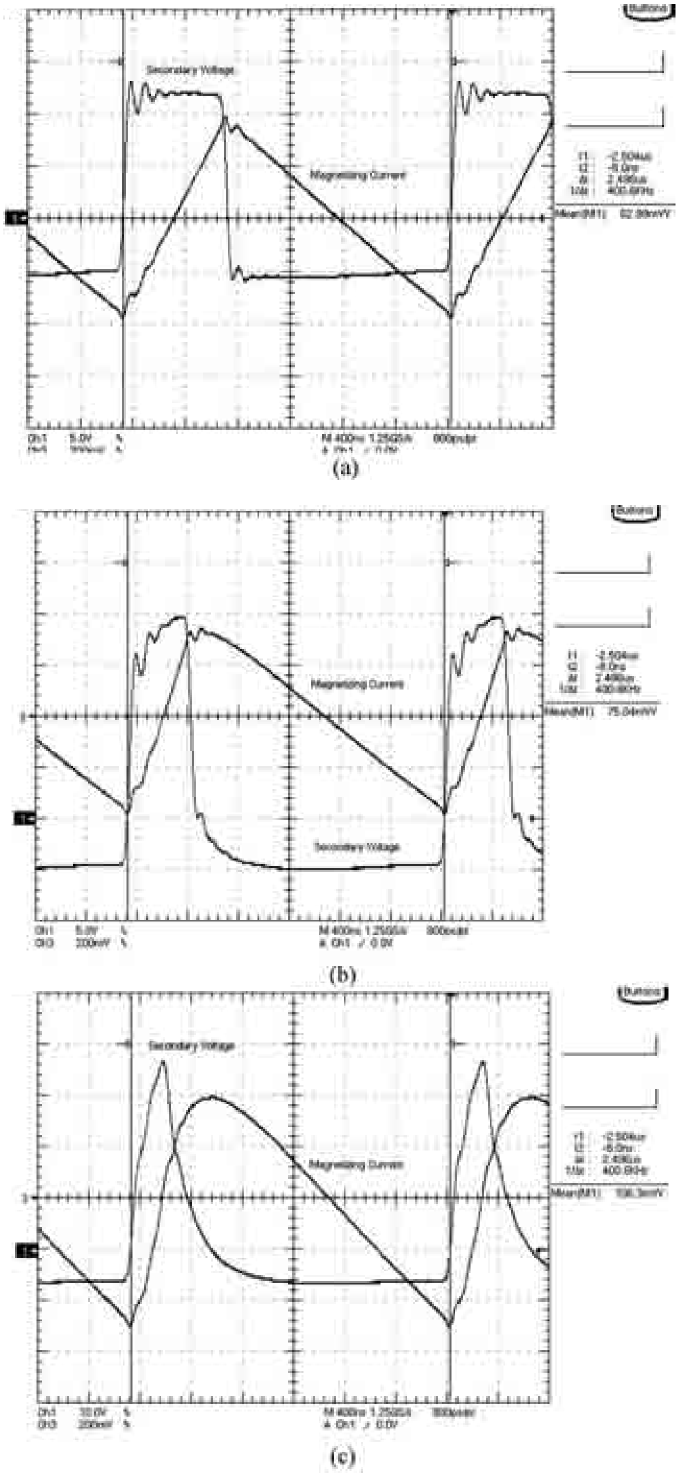
(a)

(b)

Figure 4 AHB transformer core loss results

It is clear from the test results that the core loss under PWM waveform excitation increases as the duty ratio decreases and that the addition of a DC bias current increases core loss.

Using the FEA simulation result as the reference, the difference between the measurement and the FEA simulation is within plus or minus 5% for all the measurement conditions.



(a)

(b)

(c)

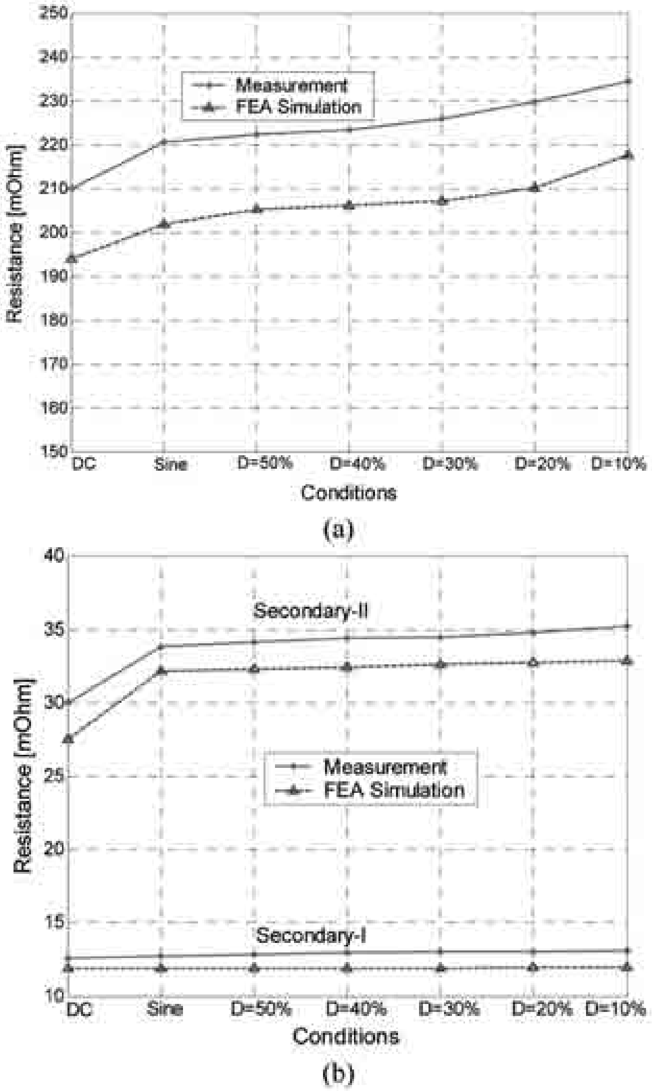
Figure 5 AHB core loss measurement waveforms: (a) Vin=35V, (b) Vin=48V, (c) Vin=75V

A. WINDING AC RESISTANCE MEASUREMENT RESULTS

The AC resistance of the AHB transformer power windings were measured and 3D FEA simulations were conducted to compare the results. The measurement and FEA simulation results are illustrated in Figure 6. The DC resistances are also provided as a reference.

Using the simulation results as reference, the difference between the measurement and FEA simulation results are within plus or minus 10% for the three AHB transformer powertrain windings. The measurement waveforms are shown for the secondary-I winding in Figure 7.

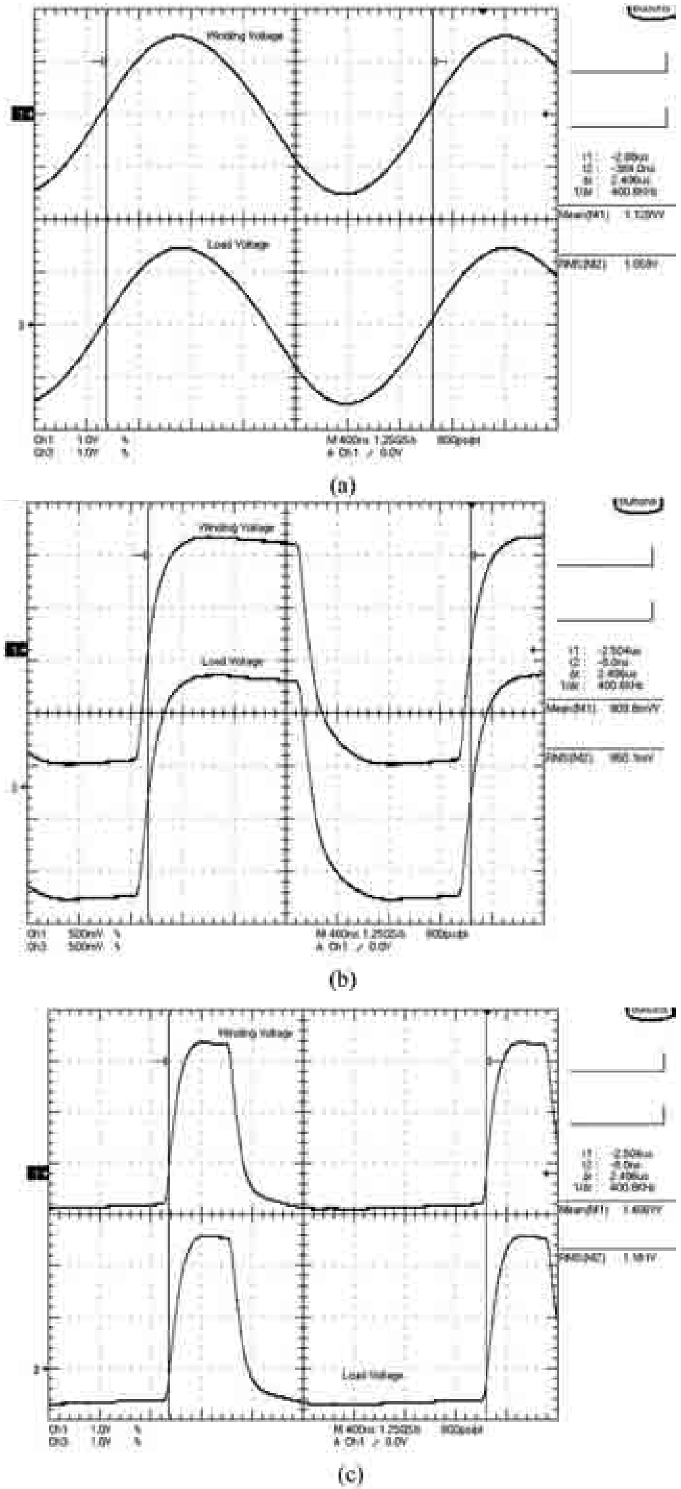
We can observe from the test results that the winding equivalent AC resistance under PWM waveform excitation is larger than that under sinusoidal excitation. In addition, the resistance increases as the duty ratio decreases.



(a)

(b)

Figure 6 AHB transformer winding AC resistance; (a) primary winding, and (b) secondary windings



(a)

(b)

(c)

Figure 7 AHB transformer secondary-I winding AC resistance measurement waveforms; (a) sinusoidal, (b) D=50%, and (c) D=20%

V. ERROR ANALYSIS

In order to ensure that the core loss and winding AC resistance measurements are accurate and valid, it is necessary to analyze the various error sources in the measurements to obtain the loss measurement accuracy.

A. ERROR ANALYSIS FOR CORE LOSS MEASUREMENT

Using (2), the core loss is determined using the winding voltage and magnetizing current. Therefore, the error analysis of the proposed core loss measurement method is based on (2). The various error sources and their effect on the core loss measurement accuracy are analyzed as follows.

1) VOLTAGE MEASUREMENT ERROR

The Tektronix TDS5054 digital oscilloscope was used for the tests. It has an 8-bit ADC. The averaging acquisition mode was used in the measurement, so, the effective sampling resolution can be as high as 11-bit. Both the digitizing and the linearity errors in the measurement are ±1/2LSB at full scale. Combining these factors, we can assume that the voltage measurement error is ±1LSB at full scale.

For the measurements, the location of the peak value of the voltage waveform measured on the oscilloscope determines the voltage measurement error. In the measurement, the peak value is always kept above 10% of the full scale (for the worst case). For the vertical scale, the voltage measurement error of the oscilloscope is less than 0.489%. Therefore, from (2), the relative error of the worst case core loss due to the voltage measurement is given by (6), which is less than 1% for the given test setup.

$$\frac{\Delta P_{Core}}{P_{Core}} = \left| \frac{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}(1\pm 0.489\%)\cdot\frac{v_{2i}(1\pm 0.489\%)}{R_{sense}}}{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}\cdot\frac{v_{2i}}{R_{sense}}} - 1 \right| = 0.98\% \tag{6}$$

2) TURNS RATIO ERROR

As explained in section II, calibration of the turns ratio between the primary and secondary windings helps to minimize error. In the turns ratio calibration procedure, (3) is used for the calculation. The peak voltage is kept close to the full scale of the oscilloscope, so, the digitizing error in the voltage measurement for the turns ratio calibration can be considered as ±1LSB of the ADC, which is 2-11.

Therefore, based on (3), the worst-case relative error for the turns ratio calibration is less than 0.1%.

In this article, the digitizing error is neglected, so, we can assume that no error is introduced into the calibration procedure of the turns ratio. Using this calibration method, the turns ratio between the primary and secondary-II winding in the AHB transformer is 2.04 from 400kHz to 2MHz. Without this turns ratio calibration, a relative error of 2% will be introduced into the core loss measurement results.

3) TOLERANCE OF THE CURRENT SENSING RESISTOR

The metal film resistor used in the core loss measurement has a tolerance of plus or minus 1%. Therefore, a 1% relative error is introduced due to the current sensing resistor.

4) TIME DELAY ERROR

Another important error source is time delay error due to the inductance of the current sensing resistor. For SMPS transformers, ideally, the voltage and current waveforms are in the wave shapes as shown in Figure 8 by the solid lines.

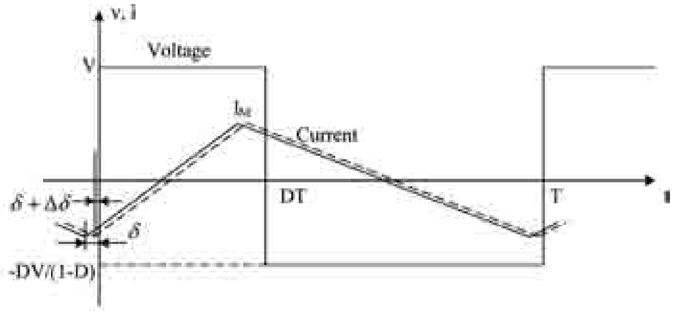


Figure 8 Ideal and typical transformer voltage and magnetizing current

The time delay between the voltage and the magnetizing current can be defined as d. Then, from (1), (7) can be derived. In (7), V is the amplitude of the positive part of voltage waveform; IM is the amplitude of the magnetizing current; D is the duty ratio of the PWM waveform; T is the switching period of the circuit; and d is the time delay between the voltage and the magnetizing current.

$$P_{Core} = V \cdot I_M \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \tag{7}$$

Since the magnetizing current is sensed by a resistor, (7) can be written as (8).

$$P_{Core} = V \cdot \frac{V_R}{R_{Sense}} \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \tag{8}$$

If some error, Delta d is introduced into the time delay, d the magnetizing current waveform will be shifted with respect to the actual waveform as illustrated by the dashed line in Figure 8. Then the incremental core loss due to this error can be calculated using (9).

$$\Delta P_{Core} = \frac{\partial P_{Core}}{\partial \delta}\Delta\delta \tag{9}$$

Using (8) and (9), the relative error of the core loss power due to Delta d is given by (10).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| = \left|\frac{2DT - 2D^2T - 2\delta}{2D\delta T - 2D^2\delta T - \delta^2}\right| |\Delta\delta| \tag{10}$$

When d <<DT and D<<D2T, (10) can be approximated by (11).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| \approx \left|\frac{\Delta\delta}{\delta}\right| \tag{11}$$

It is clear that the relative error is very sensitive to small values of d. In this case, if large time delay error is introduced, the relative error will become large. Therefore, care should be taken to minimize time delay error.

Sources of time delay error can be: poor frequency response of the current-sensing device; and trigger jitter and delays for different channels introduced by the oscilloscope.

For the digital oscilloscope used, the trigger jitter is typical at 8 ps, so, it can be ignored. The probes used for the voltage measurement are originally from the same oscilloscope and are matched to each other, so, the phase delay between channels of the oscilloscope can be neglected. The inductance associated with the current sensing resistor is the important source of the phase delay error. Therefore, in experiments, care should be taken to reduce these error sources and small inductance metal film resistor is used.

Using an impedance analyzer, phase shift less than 0.01 degree is observed for the current sensing resistor at 400kHz. It is less than 0.02 degrees at 800kHz and 0.05 degrees at 2MHz. Using the phase shift at 400kHz and transferring it to delay time for 400kHz, the time error can be calculated as given by (12).

$$\Delta\delta = \frac{0.01^\circ}{360^\circ} \times 2.5\mu\text{s} = 69.5\text{ps} \qquad (12)$$

The relative error depends on the time delay and the error introduced due to the time delay, so the value changes for different operating conditions. For example, the time delay between the voltage and magnetizing current can be calculated as d=59ns using (8) for the AHB transformer operating at 48V input. With a time delay error of Delta d=69.5ps introduced by the current sensing resistor, we can obtain the relative core loss error as less than 0.12% using (10). This calculation procedure can be applied for other operating conditions and a relative error of less than 0.2% is obtained for all the operating conditions.

B. Error Analysis for Copper Loss Measurement

The main error sources in the winding resistance measurement are: (1) voltage measurement error, (2) turns ratio error, (3) tolerance of the load resistor, (4) time delay introduce into the load current measurement.

By manipulating (4), (13) can be derived.

$$R_{Sec-AC} = R_{Load} \cdot \left(\frac{\frac{N_{Sec}}{N_{Aux}} \cdot \sum_{i=1}^{N} v_{1i} \cdot v_{2i}}{\sum_{i=1}^{N} (v_{2i})^2} - 1 \right) \qquad (13)$$

The effect of each error source on the winding AC resistance measurement is analyzed as follows.

1) VOLTAGE MEASUREMENT ERROR

The TDS5054 uses one ADC for all four channels. Therefore, the digitizing errors of the voltage measurement for each channel can be considered equal. Furthermore, the digitizing error will cancel out in the numerator and denominator in the first item in (13), so we can assume that the digitizing error can be neglected.

2) TURNS RATIO ERROR

An auxiliary winding is used to obtain the winding voltage. Since a calibration of the turns ratio is carried out to obtain the actual turns ratio, this error can be ignored.

3) TOLERANCE OF THE LOAD RESISTOR

The load resistor used in the measurement has a tolerance of plus or minus 1%, so a relative error of 1% is introduced into the winding AC resistance measurement.

4) TIME DELAY ERROR

In the load current measurement, a pure resistor value is assumed as the load. However, the inductance of the resistor and the inductance induced in the measurement circuit will introduce some time shift error for the current.

For a SMPS with a rectangular PWM voltage and current waveform as shown in Figure 9 (the leakage inductance can be neglected because it is very small), the winding AC resistance can be calculated using (14), where, V1 is the positive amplitude of the auxiliary winding voltage; V2 is the positive amplitude of the load resistor voltage; and NTurn-Ratio is the actual turns ratio between the auxiliary and the measured windings after calibration.

$$R_{Sec-AC} = R_{Load} \cdot (N_{Turn-Ratio} \cdot \frac{V_1}{V_2} - 1) \qquad (14)$$

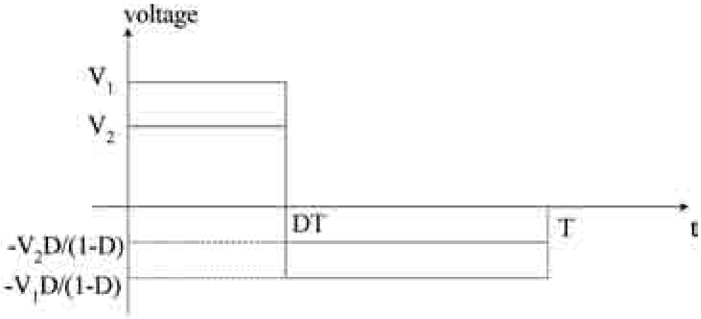


Figure 9 Typical and ideal PWM voltage and current waveform in measuring winding AC resistance

Due to the parasitic inductance, some time delay will be introduced into the load current measurement as shown in Figure 10. With this time delay, the winding AC resistance is given by (15).

$$R_{Sec-AC} = R_{Load} \left[N_{Turn-Ratio} \cdot \frac{V_1}{V_2} \left(1 - \frac{\delta}{D(1-D)T} \right) - 1 \right] \qquad (15)$$

Then, the relative error due to the time delay can be calculated using (16).

$$\frac{\Delta R_{Sec-AC}}{R_{Sec-AC}} = \frac{\frac{\delta}{D(1-D)T}}{1 - \frac{V_2}{N \cdot V_1}} \qquad (16)$$

If the load resistor is much larger than the winding AC resistance, then the ratio of V2/V1 in (16) will be very close to one. In this case, the relative error will be very sensitive to the time delay and care should be taken to minimize the parasitic inductance in the measurement.

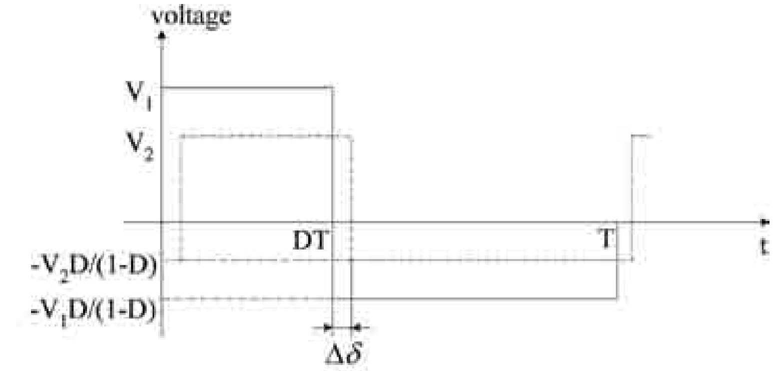


Figure 10 Time delay introduced into the load current measurement

VI. CONCLUSIONS

New measurement schemes to characterize transformer core loss and copper loss for SMPS were proposed.

Measurement results were presented for a planar transformer operating in a DC/DC power converter. FEA simulation using a time-domain solver was used to verify the measurement results. In addition, a detailed error analysis has been provided for the proposed core loss and copper loss measurement methods. The results show that the proposed methods can provide accurate measurement of transformer core loss and copper loss for high frequency SMPS.

Using the error analysis results, the relative error was calculated to be less than 5% for all the measurement conditions for the AHB transformer core loss; For the winding AC resistance, the measurement accuracy is: <2% for the primary winding, <5% for the secondary-I winding and <4% for the secondary-II winding.

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POWER TRANSFORMER DESIGN

Texas Instruments

POWER TRANSFORMER DESIGN

This article covers the design of power transformers used in buck-derived topologies: forward converter, bridge, half-bridge, and full-wave centertap.

FUNCTIONS OF A TRANSFORMER

The purpose of a power transformer in Switch-Mode Power Supplies is to transfer power efficiently and instantaneously from an external electrical source to an external load. In doing so, the transformer also provides important additional capabilities:

- The primary to secondary turns ratio can be established to efficiently accommodate widely different input/output voltage levels.
- Multiple secondaries with different numbers of turns can be used to achieve multiple outputs at different voltage levels.
- Separate primary and secondary windings facilitate high voltage input/output isolation, especially important for safety in off-line applications.

ENERGY STORAGE IN A TRANSFORMER

Ideally, a transformer stores no energy – all energy is transferred instantaneously from input to output. In practice, all transformers do store some undesired energy:

- Leakage inductance represents energy stored in the non-magnetic regions between windings, caused by imperfect flux coupling. In the equivalent electrical circuit, leakage inductance is in series with the windings, and the stored energy is proportional to load current squared.
- Mutual inductance (magnetizing inductance) represents energy stored in the finite permeability of the magnetic core and in small gaps where the core halves come together. In the equivalent circuit, mutual inductance appears in parallel with the windings. The energy stored is a function of the volt-seconds per turn applied to the windings and is independent of load current.

UNDESIRABLE EFFECTS OF ENERGY STORAGE

Leakage inductance delays the transfer of current between switches and rectifiers during switching transitions. These delays, proportional to load current, are the main cause of regulation and cross regulation problems. Reference (R4) included in this manual explains this in detail.

Mutual inductance and leakage inductance energy causes voltage spikes during switching transitions resulting in EMI and damage or destruction of switches and rectifiers. Protective snubbers and clamps are required. The stored energy then ends up as loss in the snubbers or clamps. If the loss is excessive, non-dissipative snubber circuits (more complex) must be used in order to reclaim most of this energy.

Leakage and mutual inductance energy is sometimes put to good use in zero voltage transition (ZVT) circuits. This requires caution – leakage inductance energy disappears at light load, and mutual inductance energy is often unpredictable, depending on factors like how well the core halves are mated together.

LOSSES AND TEMPERATURE RISE

Transformer loss is sometimes limited directly by the need to achieve a required overall power supply efficiency. More often, transformer losses are limited by a maximum "hot spot" temperature rise at the core surface inside the center of the windings. Temperature rise (°C) equals thermal resistance (°C/Watt) times power loss (Watts).

$$\Delta T = R_T \times P_L$$

Ultimately, the appropriate core size for the application is the smallest core that will handle the required power with losses that are acceptable in terms of transformer temperature rise or power supply efficiency.

TEMPERATURE RISE LIMIT

In consumer or industrial applications, a transformer temperature rise of 40-50°C may be acceptable, resulting in a maximum internal temperature of 100°C. However, it may be wiser to use the next size larger core to obtain reduced temperature rise and reduced losses for better power supply efficiency.

LOSSES

Losses are difficult to predict with accuracy. Core loss data from core manufacturers is not always dependable, partly because measurements are made under sinusoidal drive conditions. Low frequency winding losses are easy to calculate, but high frequency eddy current losses are difficult to determine accurately, because of the high frequency harmonic content of the switched rectangular current waveshape. Section 3 discusses this problem extensively.

Computer software can greatly ease the difficulty of calculating the winding losses, including high order harmonics(1).

THERMAL RESISTANCE

Temperature rise depends not only upon transformer losses, but also upon the thermal resistance, RT (°C/Watt), from the external ambient to the central hot spot. Thermal resistance is a key parameter, unfortunately very difficult to define with a reasonable degree of accuracy. It has two main components: internal thermal resistance RI between the heat sources (core and windings) and the transformer surface, and the external thermal resistance RE from the surface to the external ambient.

Internal thermal resistance depends greatly upon the physical construction. It is difficult to quantify because the heat sources are distributed throughout the transformer. RI from surface to internal hot spot is not relevant because very little heat is actually generated at that point. Most of the heat generated in the core (other than in toroids) is near the transformer surface. Heat generated within the winding is distributed from the surface to the internal core. Although copper has very low thermal resistance, electrical insulation and voids raises the RT within the winding.

This is a design area where expertise and experience is very helpful. Fortunately, internal thermal resistance is considerably smaller than external RE (except with high velocity forced air cooling), and while RI shouldn't be ignored, it usually is not critically important compared with RE.

External RE is mainly a function of air convection across the surface of the transformer – either natural convection or forced air. RE with natural convection cooling depends greatly upon how the transformer is mounted and impediments to air flow in its vicinity.

A transformer mounted on a horizontal surface and surrounded by tall components, or mounted in a relatively small enclosure will have considerably greater RE than if it were mounted on a vertical surface, benefiting from the "chimney effect". With forced air cooling, RE can be driven down to a very small value, depending on air velocity, in which case internal RI becomes the primary concern. With forced air cooling, thermal resistance and temperature rise often become irrelevant, because an absolute loss limit to achieve power supply efficiency goals becomes dominant.

For the average situation with natural convection cooling, a crude "rule of thumb" can be used:

$$R_E = \frac{800^\circ\text{C - cm}^2\text{ / Watt}}{A_S \text{ in cm}^2} \quad {}^\circ\text{C / Watt}$$

Where AS is the total surface area of the transformer, excluding the mounting surface. Calculating AS is time-consuming, but another rule of thumb simplifies this, as well. For a given class of cores, such as E-E cores in the ETD or EC series, the relative proportions are quite similar for all core sizes. Thus for all cores in the ETD or EC series, the usable surface area, AS, is approximately 22 times the winding window area, AW. Combining this with the equation above enables the window area, AW, from the core data sheet, to be used to directly calculate the external thermal resistance:

$$R_E = \frac{36}{A_W \text{ in cm}^2} \quad {}^\circ\text{C / Watt}$$

For pot cores or PQ cores, window areas are proportionately smaller, and not as consistent. AS/AW may range from 25 to 50, so that RE may range from 16/AW to 32/AW °C/W.

Experience is a great help in minimizing and crudely quantifying thermal resistance. In the final analysis, an operational check should be conducted with a thermocouple cemented at the hot spot near the middle of the centerpost, with the transformer mounted in a power supply prototype or mockup.

WORST-CASE LOSSES

Transformer losses should be examined under worst-case conditions that the power supply is expected to operate over long periods of time, not under transient conditions.

Transformer losses can be put into three major categories: core hysteresis losses, core eddy current losses, and winding losses.

Core hysteresis losses are a function of flux swing and frequency. In all buck-derived applications under steady-state conditions, VIN•D = n•VO. Under fixed frequency operation, volt-seconds and therefore flux swing are constant. Hysteresis loss is therefore constant, regardless of changes in VIN or load current.

Core eddy current loss, on the other hand, is really I2R loss in the core material. If VIN doubles, Peak I2R loss quadruples, but since D is halved, average I2R loss doubles. Thus core eddy current loss is proportional to VIN. Worst case is at high VIN.

Winding losses: In buck-derived regulators, peak secondary current equals load current and peak primary current equals load current divided by the turns ratio:

$$I_{Spk} = I_L \;\; ; \quad I_{Ppk} = I_L / n$$

Peak currents are independent of VIN. But at constant peak currents (constant load), rms current squared (and I2R loss) is proportional to duty cycle D and inversely proportional to VIN.. (With constant peak current, high order harmonics depend mostly on switching transitions and do not vary significantly with D.) In buck-derived regulators, winding loss is always greatest at low VIN.

Ferrite cores: In most ferrite materials used in SMPS applications, hysteresis losses dominate up to 200-300kHz. At higher frequencies, eddy current losses take over, because they tend to vary with frequency squared (for the same flux swing and waveshape).

Thus, at frequencies up to 200-300kHz, worst case is at low VIN and full load because of high winding losses. Once core eddy current losses become significant, they rise rapidly with frequency, especially at high VIN. (The increase in eddy current loss with high VIN, small D, is not shown in core manufacturer's loss curves because they assume sinusoidal waveforms.) Winding losses also rise with frequency, especially at low VIN. To maintain a reasonable RAC/RDC, Litz wire with more strands of finer wire must be used, raising RDC because increased insulation and voids reduce the copper area. Thus, at frequencies where core eddy current losses dominate, core loss worst case is at high VIN, full load. Winding loss worst case is always at low VIN, full load.

Laminated metal alloy and powdered metal cores: Core eddy current losses dominate, hence worst case is at high VIN, full load. Winding losses are worst case at low VIN, full load.

BALANCING CORE AND WINDING LOSSES

At SMPS operating frequencies, when the core is usually loss-limited, not saturation limited, total losses are at a broad minimum when core losses are approximately equal to or a little less than winding losses. Likewise, winding losses are at a minimum and well distributed by making the rms current density approximately equal in all windings. With a bridge or half-bridge primary, which has good winding utilization, and center-tapped secondaries which have poor utilization, rms current densities will be approximately equalized when the primary conductor cross-section area is 40% and the secondaries 60% of the available area. In most other cases, primary and secondary conductor areas should be 50%/50%, including:

Forward converter (single-ended primary/secondary SE/SE), C.T. primary/C.T. secondary, bridge-half bridge primary/bridge secondary.

The above allocations can be impossible to achieve because the number of turns in each winding must be an integral number. In a low voltage secondary, 1.5 turns may be required for optimum balance between core and winding losses. With one turn, the flux swing and core loss may be much too large; with two turns the winding loss becomes too great. At either extreme, it may be impossible to meet temperature rise or absolute loss limits. A larger core may be required to resolve this problem.

WINDOW UTILIZATION

This subject is discussed extensively in Section 3.

As a reminder:

• Safety isolation requirements impose minimum dimensional limits for creepage and insulation thickness which can waste a high percentage of window area, especially in a small transformer. A bobbin also reduces the area available for windings.

Triple insulated wire satisfies the insulation thickness requirement and eliminates the creepage requirement. It is worth considering, especially for small transformers where creepage distances take up a large percentage of window area.

• In the reduced window area that is available for the windings, much of the actual winding area is taken up by voids between round wires and by wire insulation. In a winding consisting of many turns of single, round, insulated wires, only 70-75% of the area available for that winding is likely to be conductor metal - “copper”. With Litz wire, the copper area is reduced further. For every level of twisting, an additional 0.75 factor (approximate) applies. For example, with Litz wire 7 strands of 7 strands (49 total wires), the copper area would be .75•.75•.75 = 42% of the area available for that winding. On the other hand, a winding consisting of layers (turns) of copper foil or strap, there are no voids, only the insulation between turns. Winding area utilization could be as much as 80 90% copper area.

TOPOLOGY

The choice of circuit topology obviously has great impact on the transformer design, but a detailed discussion is beyond the scope of this topic.

There is a great deal of overlap in topology usage. Flyback circuits (flyback transformers are covered in Section 5) are used primarily at power levels in the range of 0 to 150 Watts, Forward converters in the range of 50 to 500 Watts, half-bridge from 100 to 1000 Watts, and full bridge usually over 500 Watts.

Full bridge and half-bridge topologies with full bridge secondaries have the best transformer efficiency because the core and the windings are fully utilized. With center-tapped secondaries, winding utilization and efficiency are reduced. With centertapped primary and secondaries, winding utilization and efficiency are further reduced. All of the push-pull topologies have the further advantage that for a given switching frequency, giving the same output ripple filtering and closed loop capability, the frequency at which the transformer core and windings operate is halved, reducing core and ac winding losses.

Forward converter transformers have the poorest utilization and efficiency because neither the core nor the windings are used during the lengthy core reset interval.

FREQUENCY

There are several meanings to the term “frequency” in switching power supply applications, and it is easy for confusion to arise.

In this article, “switching frequency”, fS, is defined as the frequency at which switch drive pulses are generated. It is the frequency seen by the output filter, the frequency of the output ripple and input ripple current, and is an important concept in control loop design. In a single-ended power circuit such as the forward converter, the power switch, the transformer, and the output rectifier all operate at the switching frequency and there is no confusion. The transformer frequency and the switching frequency are the same.

“Clock frequency” is the frequency of clock pulses generated in the control IC. Usually, the switching frequency is the same as the clock frequency, but not always. Occasionally, the control IC may divide the clock frequency to obtain a lower switching frequency. It is not unusual for a push-pull control IC to be used in a single-ended forward converter application, where only one of the two switch drivers is used, to guarantee 50% maximum duty cycle. In this case the switching frequency is half the clock frequency.

Confusion often arises with push-pull topologies. Think of the push-pull power circuit as a 2:1 frequency divider, with the transformer and the individual switches and individual rectifiers operating at a “transformer frequency”, fT, which is one-half of the switching frequency. Collectively, the switches and rectifiers operate at the switching frequency, but the transformer operates at the transformer frequency.

Some designers define “switching frequency” as the frequency that the individual switch and the transformer operate at, but this requires redefining the term “switching frequency” when dealing with output ripple and in control loop design.

DUTY CYCLE

Duty cycle, D, is defined as the amount of time the power switch is on in relation to the switching period: D = tON/TS.

In a single-ended forward converter, this is clearly understood, but in a push-pull circuit, ambiguity often arises. For example, in a half-bridge circuit operating at minimum VIN, the duty cycle is likely to be in the vicinity of 90% (D = 0.9). The transformer is delivering power to the output 90% of the time, there is a voltage pulse applied to the filter input 90% of the time, etc. But individual power switches and individual rectifiers, which conduct only during alternate switching periods, can be said to operate at a duty cycle of 45%. That is true, but it is better to think of them as operating at D/2, retaining a consistent definition of D throughout the power supply design.

MAXIMUM DUTY CYCLE

In normal steady-state operation of a buck-derived regulator, VIN•D is constant. The control loop changes duty cycle D inversely proportional to VIN to maintain a constant output voltage, VO. (VIND = n•VO'), where n is the turns ratio NP/NS, and VO' equals output voltage VO plus diode forward voltage drop at full load.

At a fixed switching frequency and with normal steady-state operation, the volt-seconds applied to the transformer windings are constant, independent of line voltage or load current.

$$V_{IN}t_{on} = \frac{V_{IN}D}{f_S} = \frac{nV_O'}{f_S}$$

The maximum duty cycle, Dmax, associated with minimum VIN in normal steady-state operation, is limited by a variety of considerations:

In a forward converter, a substantial portion of each switching period must be allowed for core reset.

If the voltage backswing during reset is clamped to VIN, the duty cycle must be limited to less than 50% because the time required for reset equals the switch ON time.

In a push-pull converter (bridge, half-bridge, PPCT) duty cycle can approach 100% at the switching frequency (always think of D at the switching frequency, not the transformer frequency). However, it may be necessary to limit D to less than 90% to allow a current transformer to self-reset.

Often the control IC limits the duty cycle for several reasons including allowing time for delays in turning off the switch.

At low VIN, if normal Dmax is right at the duty cycle limit, the regulator has no reserve volt-second capability and cannot respond rapidly to a sudden load increase occurring when VIN is low. It may be desirable to make the "normal" Dmax less than the absolute limit, Dlim, to provide a little headroom in this situation.

A potentially serious problem needs to be considered:

During initial start-up of the power supply, or following a sudden large increase in load current which temporarily pulls down Vout, the control loop calls for full current, pushing the duty cycle to its absolute maximum limit, Dlim. The output filter inductor limits the current rate of rise, so that for several switching frequency periods, the duty cycle is at the limit, Dlim. During the transient event described above, Dlim could occur when VIN is maximum.

Thus, the volt-seconds applied to the transformer windings could be several times larger than normal:

Limit VIND = VINmaxDlim
Normal VIND = VINminDmax

The flux swing, also several times greater than normal, could saturate the core. (The increased core loss is not a problem – it is only temporary.)

This may not be a problem if the ratio limit/normal VIND is small and/or if the normal flux density swing, limited by core loss, is a small fraction of Bsat (Bsat - Br for a forward converter). For example, if limit/normal VIND is 3:1, and if normal Delta B is 0.08T, then with Bsat greater than 0.24T, there is no problem.

If this problem exists, soft-start circuitry can eliminate it during start-up, but soft-start has no effect when the load increases rapidly. A few IC control circuits have volt-second limiting capability, but the vast majority do not. The soft saturation characteristic of power ferrite material may be forgiving enough to allow the core to saturate, with the absolute current limit providing protection, but with sharp-saturation core materials, this is a likely disaster. If all else fails, the normal flux swing must be reduced to the point where the abnormal flux swing does not reach saturation.

RESTRICTIONS ON NUMBER OF TURNS

Choices regarding the number of turns and turns ratios are often severely limited by low voltage secondaries. For a 5 Volt output the alternatives might be a 1-turn or a 2-turn secondary–a 2 to 1 step in the number of turns in every winding. For the same size core and window, this doubles the current density in the windings and accordingly increases the loss.

Choices may be further restricted when there are multiple low voltage secondaries. For example, a 2.5 to 1 turns ratio may be desirable between a 12 Volt and a 5 Volt output. This is easily accomplished with a 2-turn 5V secondary and a 5-turn 12V winding. But if the 5V secondary has only 1 turn, the only choice for the 12V secondary is 3 turns, which may result in excessive linear post-regulator loss. This problem could be handled by the use of fractional turns – see reference (R6).

There are no hard and fast rules to follow in establishing the optimum turns for each winding, but there is some general guidance. First, define the ideal turns ratios between windings that will achieve the desired output voltages with the normal VIND established earlier. Later, when a specific core has been tentatively selected, the turns ratios will translate into specific turns, but these are not likely to be the integral numbers required in practice. It then becomes a juggling act, testing several approaches, before reaching the best compromise with integral turns. The lowest voltage secondary usually dominates this process, because with small numbers the jumps between integral turns are a larger percentage. Especially if the lowest voltage output has the greatest load power, which is often the case, the lowest voltage secondary is rounded up or down to the nearest integral.

Rounding down will increase core loss, rounding up will increase winding loss. If the increased loss is unacceptable, a different core must be used that will require less adjustment to reach an integral number of turns. The low voltage output is usually regulated by the main control loop.

Higher voltage secondaries can be rounded up to the next integral with less difficulty because they have more turns. However, it is unlikely that accuracy or load regulation will be acceptable, requiring linear or switched post-regulation.

Since the primary is usually higher voltage, the primary turns can usually be set to achieve the desired turns ratio without difficulty.

Once the turns have been established, the initial calculations must be redefined.

FLUX WALKING

Faraday's Law states that the flux through a winding is equal to the integral volt-seconds per turn.

This requires that the voltage across any winding of any magnetic device must average zero over a period of time. The smallest DC voltage component in an applied AC waveform will slowly but inevitably "walk" the flux into saturation.

In a low frequency mains transformer, the resistance of the primary winding is usually sufficient to control this problem. As a small DC voltage component pushes the flux slowly toward saturation, the magnetizing current becomes asymmetrical. The increasing DC component of the magnetizing current causes an IR drop in the winding which eventually cancels the DC voltage component of the drive waveform, hopefully well short of saturation.

In a high frequency switchmode power supply, a push-pull driver will theoretically apply equal and opposite volt-seconds to the windings during alternate switching periods, thus "resetting" the core (bringing the flux and the magnetizing current back to its starting point). But there are usually small volt-second asymmetries in the driving waveform due to inequalities in MOSFET RDSon or switching speeds.

The resulting small DC component will cause the flux to "walk". The high frequency transformer, with relatively few primary turns, has extremely low DC resistance, and the IR drop from the DC magnetizing current component is usually not sufficient to cancel the volt-second asymmetry until the core reaches saturation.

Flux walking is not a problem with the forward converter. When the switch turns off, the transformer magnetizing current causes the voltage to backswing, usually into a clamp. The reverse voltage causes the magnetizing current to decrease back to zero, from whence it started. The reverse volt-seconds will exactly equal the volt-seconds when the switch was ON.

Thus the forward converter automatically resets itself (assuming sufficient reset time is allowed, by limiting the maximum duty cycle).

The flux walking problem is a serious concern with any push-pull topology (bridge, half-bridge or push-pull CT), when using voltage mode control.

One solution is to put a small gap in series with the core. This will raise the magnetizing current so that the IR drop in the circuit resistances will be able to offset the DC asymmetry in the drive waveform.

But the increased magnetizing current represents increased energy in the mutual inductance which usually ends up in a snubber or clamp, increasing circuit losses.

A more elegant solution to the asymmetry problem is an automatic benefit of using current mode control (peak or average CMC). As the DC flux starts to walk in one direction due to volt-second drive asymmetry, the peak magnetizing current becomes progressively asymmetrical in alternate switching periods. However, current mode control senses current and turns off the switches at the same peak current level in each switching period, so that ON times are alternately lengthened and shortened. The initial volt-second asymmetry is thereby corrected, peak magnetizing currents are approximately equal in both directions, and flux walking is minimized.

However, with the half-bridge topology this creates a new problem. When current mode control corrects the volt-second inequality by shortening and lengthening alternate pulse widths, an ampere-second (charge) inequality is created in alternate switching periods. This is of no consequence in full bridge or push-pull center-tap circuits, but in the half-bridge, the charge inequality causes the capacitor divider voltage to walk toward the positive or negative rail.

As the capacitor divider voltage moves away from the mid-point, the volt-second unbalance is made worse, resulting in further pulse width correction by the current mode control. A runaway situation exists, and the voltage will walk (or run) to one of the rails. This problem is corrected by adding a pair of diodes and a low-power winding to the transformer, as detailed in the Unitrode Applications Handbook.

CORE SELECTION: MATERIAL

Select a core material appropriate for the desired transformer frequency.

With power ferrites, higher frequency materials have higher resistivity, hence lower eddy current losses. However, the permeability is generally lower, resulting in greater magnetizing current, which must be dealt with in snubbers and clamps.

With metal alloy cores, the higher frequency materials have higher resistivity and require very thin laminations. Although saturation flux density is usually very much greater than with ferrite materials, this is usually irrelevant because flux swing is severely limited by eddy current losses.

Ferrite is the best choice in transformer applications except for mechanical ruggedness.

CORE SELECTION: SHAPE

The window configuration is extremely important. The window should be as wide as possible to maximize winding breadth and minimize the number of layers. This results in minimized Rac and leakage inductance. Also, with a wide window, the fixed creepage allowance dimension has less impact. With a wider window, less winding height is required, and the window area can be better utilized.

Pot cores and PQ cores have small window area in relation to core size, and the window shape is almost square. The creepage allowance wastes a large fraction of the window area, and the winding breadth is far from optimum. These cores are not as well suited for high frequency SMPS applications. One advantage of pot cores and PQ cores is that they provide better magnetic shielding than E-E cores, reducing EMI propagation.

EC, ETD, LP cores are all E-E core shapes. They have large window area in relation to core size, and the window has the desirable wide configuration.

Toroidal cores, properly wound, must have all windings distributed uniformly around the entire core. Thus the winding breadth is essentially the circumference of the core, resulting in the lowest possible leakage inductance and minimizing the number of winding layers. There is no creepage allowance because there is no end to the windings. (But there is a problem bringing the leads out.) Stray magnetic flux and EMI propagation are also very low.

The big problem with toroidal cores is the winding difficulty, especially with the shapes and gauge of conductors used in SMPS transformers. How can a 1-turn secondary be spread around the entire toroid? Automatic winding is virtually impossible. For this reason, toroidal shapes are seldom used in SMPS transformers.

Planar cores with their low profile are becoming more popular as SMPS frequencies progressively increase.

Planar cores introduce a new set of unique problems which are beyond the scope of this discussion.

Be assured that Faraday's and Ampere's Laws still apply, but in a planar core, flux density and field intensity change considerably throughout the important regions, making calculation much more difficult.

CORE SELECTION: SIZE

A novice in the art of transformer design usually needs some guidance in making an initial estimate of the core size appropriate for the application requirements.

One widely used method, with many variations, is based on the core Area Product, obtained by multiplying the core magnetic cross-section area by the window area available for the winding.

There are many variables involved in estimating the appropriate core size. Core power handling capability does not scale linearly with area product or with core volume. A larger transformer must operate at a lower power density because heat dissipating surface area increases less than heat-producing volume.

The thermal environment is difficult to evaluate accurately, whether by forced air or natural convection.

Some core manufacturers no longer provide area product information on their data sheets, often substituting their own methodology to make an initial core size choice for various applications.

The following formula provides a crude indication of the area product required:

$$AP = A_W A_E = \left(\frac{P_O}{K \, \Delta B \, f_T} \right)^{4/3} \quad cm^4$$

where:

P_O = Power Output
ΔB = Flux density swing, Tesla
f_T = *Transformer* operating frequency
K = .014 (Forward converter,PPCT)
= .017 (Bridge, half bridge)

This formula is based on current density of 420A/cm2 in the windings, and assumes a window utilization of 40% copper. At low frequencies, the flux swing is limited by saturation, but above 50kHz (ferrite), Delta B is usually limited by core losses. Use the Delta B value that results in a core loss of 100mW/cm3 (2 times the "flux density" given in the core loss curves).

These initial estimates of core size are not very accurate, but they do reduce the number of trial solutions that might otherwise be required. In the final analysis, the validity of the design should be checked with a prototype transformer operated in the circuit and the environment of the application, with the hot spot temperature rise measured by means of a thermocouple cemented to the center of the centerpost.

TRANSFORMER DESIGN COOKBOOK

The steps for designing a power transformer for SwitchMode Power Supplies are outlined below. A typical example is carried through to illustrate the process. There are many approaches to transformer design. The approach presented here appears the most logical and straightforward to the author.

It may be worthwhile to use software such as "Magnetic Designer" from Intusoft(2) for the initial design, using the approach defined herein for verification and tune-up. The author has not evaluated "Magnetic Designer" sufficiently to make an unqualified endorsement, but it should certainly make a good starting point and take a great deal of drudgery out of the process. It has the advantage of including an extensive core database.

INITIAL PREPARATION

The first few steps in this process define application parameters that should not change, regardless of subsequent iterations in the selection of a specific core type and size.

If the results are not acceptable, start over from the very beginning, if that seems appropriate. Great difficulty in achieving an acceptable forward converter transformer design may be a subtle message that a half-bridge topology is perhaps a better choice.

Step 1. Define the power supply parameters pertaining to the transformer design:

V_{IN} Range:	100 - 190 V
Output 1:	5 V, 50 A
Output 2:	none
Circuit Topology:	Forward Converter
Switching Freq, f_S:	200 kHz
Transformer Freq, f_T:	200 kHz
Max Loss (absolute):	2.5 W
Max °C Rise:	40°C
Cooling Method:	Natural Convection

Step 2. Define absolute duty cycle limit Dlim, tentative normal Dmax at low VIN (to provide headroom for dynamic response), and normal VIND:

Absolute Limit, Dlim:	0.47
Normal Dmax:	0.42
Normal V_{IN}•D :	V_{IN}min•Dmax = 42 V
V_{IN}maxDlim:	89.3 V

Step 3. Calculate output voltages plus diode and secondary IR drops at full load:

Vo1':	5.0 + 0.4 = 5.4 Volts
Vo2':	n/a

Step 4. Calculate desired turns ratios: P-S1; S1-S2, etc. Remember that choices with low voltage secondaries will probably be limited.

$n = N_P/N_{S1} = V_{IN}D/V_{O1}'$: 42/5.4 = 7.8
Possible choices: 8:1 ; 7:1 ; 15:2

CORE SELECTION

Step 5: Tentatively select core material, shape and tentative size, using guidance from the manufacturer's data sheet or using the area product formula given previously in this paper. Will a bobbin be used?:

Core Material: Ferrite, Magnetics Type P
Core type, Family: ETD
Core Size: 34mm – ETD34

Step 6: For the specific core selected, note: Effective core Area, Volume, Path Length. (cm)

A_e: 0.97 cm^2
V_e: 7.64 cm^3
ℓ_e: 7.9 cm

Window Area, Breadth, Height, Mean Length per Turn (' indicates net with bobbin, creepage).

A_w / A_w': 1.89 / 1.23 cm^2
bw / bw': 2.36 / 1.5 cm
hw / hw': 0.775 / 0.6 cm
MLT: 5.8 / 6.1 cm

DEFINE RT AND LOSS LIMIT

Step 7: Obtain thermal resistance from data sheet or calculate from window area (not bobbin area) from formula for EC and ETD series:

$$R_T = \frac{800}{22 \bullet A_W \text{ in } cm^2} = \frac{38}{1.89} = 19\ °C/Watt$$

Calculate loss limit based on max. temperature rise:

$$Plim = °Crise/R_T: \qquad = 40/19 = 2.1 \text{ Watts}$$

The 2.1W limit applies, since it is less than theabsolute limit from Step 1. Tentatively apportion half to core loss, half to winding loss.

PClim: 1 Watt
PWlim: 1.1 Watt

Step 8: Loss Limited Flux Swing

Calculate max. core loss per cm^3

PClim/Ve = 1/7.64 = 131 mw/cm^3 (= kW/m^3)

Using this core loss value, enter the core loss curve for the P material selected. At the *transformer* frequency, find "flux density" (actually peak flux density). Double it to obtain the loss-limited peak-peak flux density swing, ΔB:

At 131 mw/cm^3 and 200kHz:

ΔB = 2•800 Gauss = 1600G = 0.16 Tesla

Normal $\Delta\ \phi = \Delta B \bullet A_e$

Step 9: Using Faraday's Law, calculate the number of secondary turns:

$$\int E_{S1}\,dt = Vpk_{S1}t_{ON} = V_{O1}{}' \bullet T_S$$

$$N_{S1} = \int E_{S1}dt/\Delta\ \phi = V_{O1}{}' \bullet T_S/\Delta\ \phi$$

$$N_{S1} = \frac{V_{O1}{}'\,T_S}{\Delta B \times A_E} = \frac{5.4 \times 5 \times 10^{-6}}{.16 \times .97 \times 10^{-4}} = 1.74 \text{ Turns}$$

Rounding down to 1 turn will greatly increase the volts/turn, flux swing and core losses. Rounding up to 2 turns reduces core losses but increases winding loss. Since the result above is much closer to 2 turns, this will be adopted.

Step 10: Recalculate flux swing and core loss at 2 turns:

$$\Delta B(2 \text{ turns}) = 0.16\text{T}\,\frac{1.74\text{turns}}{2 \text{ turns}} = 0.14\text{Tesla}$$

From the core loss curves, loss at 0.14T/2 (700 Gauss) is 110mw/cm^3 x 7.64cm^3

Core loss = 0.84 W

Step 11: Finalize the choice of primary turns. A larger turns ratio results in lower peak current, larger D (less reserve), and more copper loss. From the possibilities defined in Step 4, trial solutions show the best choice to be NP = 15 turns (7.5:1 turns ratio).

Recalculate normal VIND and flux swing under worst case VINmaxDlim conditions:

VIND = nVO' = 7.5•5.4 = 40.5 V

ΔBlim = 0.14T•89.3/40.5 = 0.31T -- OK

Step 12: Define the winding structure.

An interleaved structure will be used, as shown in Figure 4-1, to minimize leakage inductance and winding losses.

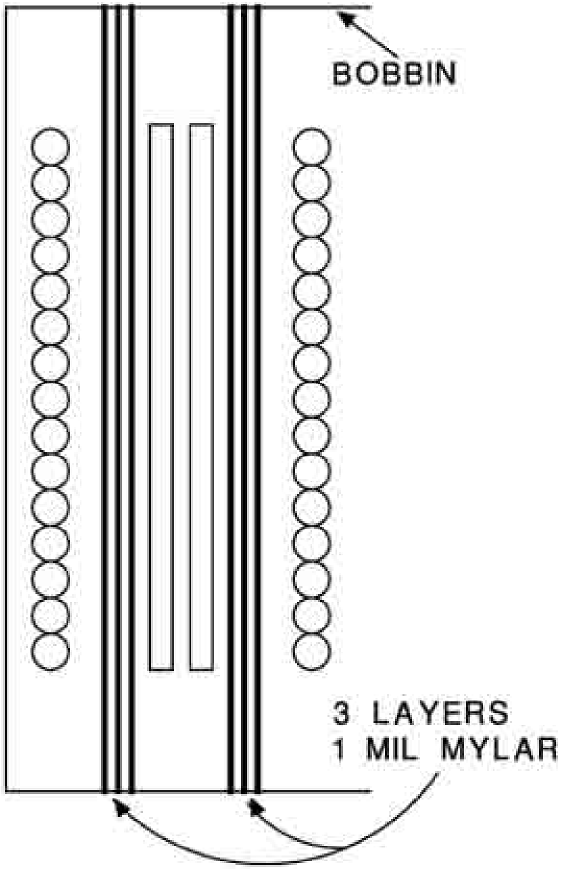


Figure 1

The interleaved structure results in two winding sections. Primary windings of 15 turns in each section are connected in parallel. Primary current divides equally in the two paralleled windings because this results in the lowest energy transfer. Secondary windings of 1 turn copper foil in each section are connected in series, resulting in a 2-turn secondary.

With only one turn in each section, the secondary windings can be much thicker than DPEN to minimize DC resistance without increasing the ac resistance.

Step 12: Calculate DPEN at 200 kHz:

$$D_{pen} = 7.6/\sqrt{f} = 7.6/\sqrt{200{,}000} = .017\text{ cm}$$

Step 13: Calculate dc and rms AC currents in each winding at VINmin and Dmax. (Ref. Section 3):

$$I_{Sdc} = 50A \cdot D_{max} = 50 \cdot 0.405 = 20.25A$$

$$I_{Sac} = I_{Sdc}((1-D)/D)^{1/2} = 24.5A$$

$$I_{Pdc} = I_{Sdc}/n = 20.25/7.5 = 2.7A$$

$$I_{Pac} = I_{Sac}/n = 24.5/7.5 = 3.27A$$

Primary current in each of the two paralleled sections is one-half the total primary current: 1.35Adc and 1.65Aac.

Step 14: Define the primary winding:

One layer of 15 turns spread across the available winding breadth of 1.3cm allows a maximum insulated wire diameter of 0.87mm. AWG 21 – 0.72mm copper will be used.

From Ref R2, pg 9, the effective layer thickness equals 0.83•dia(dia/spacing)1/2.

$$Q = (\text{layer thickness})/D_{PEN}$$
$$Q = 0.83 \cdot .072(.072/.087)^{1/2}/.017 = 3.19$$

From Dowell's curves, Rac/Rdc for 1 layer is 3.1.

This will result in unacceptable AC losses.

A Litz wire consisting of 100 strands #42 wire has a diameter of 0.81mm and a resistance of 0.545m ohms/cm.

The DC resistance of the single layer is:

$$R_{dc} = \Omega/\text{cm} \cdot MLT \cdot N_s = .00055 \cdot 6.1 \cdot 15 = .05\Omega$$

Multiplying by (1.35A DC)2, DC power loss is 0.091W in each section, for a total primary DC loss of 0.18W.

The diameter of each #42 wire is 0.064mm, but there are effectively ten layers of fine wire in the single layer of Litz wire. This is because the 100 strands are roughly equivalent to a 10 x 10 array, thus ten wires deep. Q is approximately 1/10 the value for solid wire, or 0.3, resulting in Rac/Rdc of 1.2. Thus, Rac = Rdc•1.2, or .06 ohms.

Multiplying by 1.65A squared, the AC loss is 0.16W in each section, for a total primary AC loss of 0.32W. Adding the 0.18W DC loss,

Total primary power loss = 0.5 Watts.

Step 15: Define the secondary winding.

The secondary consists of two turns (two layers) of copper strip or foil, 1.3cm wide (full available winding breadth), and 0.13cm thick. There is one secondary layer in each of the two sections of the interleaved winding structure. This permits the thickness of the copper strip to be much greater than DPEN to minimize DC losses, without increasing AC losses.

This is because AC current flows only on the outer side of each turn. As the conductor is made thicker, Rac/Rdc becomes larger, but Rdc decreases and Rac remains the same.

With a solid copper secondary, the layer thickness is the same as the conductor thickness, 0.1cm.

$$Q = \text{Layer thickness}/D_{PEN} = 0.13/.017 = 7.6$$
$$R_{ac}/R_{dc} = 7.5$$

This will be acceptable because the dc resistance is very low.

$$R_{dc} = \rho \cdot MLT \cdot N_s/(bw'h)$$
$$R_{dc} = 2.3 \cdot 10^{-6} \cdot 6.1 \cdot 2/(1.3 \cdot 0.13) = 166\mu\Omega$$
$$P_{dc} = 166\mu\Omega \cdot 20.25^2 = .068\text{ W}$$
$$P_{ac} = R_{dc} \cdot R_{ac}/R_{dc} \cdot I_{ac}^2 = 166\mu\Omega \cdot 7.5 \cdot 24.5^2$$
$$P_{ac} = 0.75\text{ W}$$

Total secondary loss:

.068W + 0.75W = 0.82 W

Total copper loss:

0.82W + 0.5W = 1.32 W

Total core plus copper loss:

0.84W + 1.32W = 2.16 Watts

Thus, the total power loss is under the absolute limit of 2.5Watts, but slightly over the 2.1 Watt limit based on the desired maximum temperature rise of 40°C.

REFERENCES:

(R2) "Eddy Current Losses in Transformer Windings and Circuit Wiring," Unitrode Seminar Manual SEM600, 1988 (reprinted in the Reference Section at the back of this Manual)

(R4) "The Effects of Leakage Inductance on Switching Power Supply Performance," Unitrode Seminar Manual SEM100, 1982 (reprinted in the Reference Section at the back of this Manual)

(R6) "How to Design a Transformer with Fractional Turns," Unitrode Seminar Manual SEM500, 1987 (reprinted in the Reference Section at the back of this Manual)

(1) PROXY — Proximity effect analysis, KO Systems, Chatsworth, CA, 818-341-3864

(2) "Magnetics Designer," Magnetics design software, IntuSoft, San Pedro, CA 310-833-0710

POWER TRANSFORMER MAINTENANCE AND TESTING

Chief of Engineers, United States Army

CHAPTER 1
INTRODUCTION/SAFETY

1-1. PURPOSE

This manual contains a generalized overview of the fundamentals of transformer theory and operation.

The transformer is one of the most reliable pieces of electrical distribution equipment (see figure l-l). It has no moving parts, requires minimal maintenance, and is capable of withstanding overloads, surges, faults, and physical abuse that may damage or destroy other items in the circuit. Often, the electrical event that burns up a motor, opens a circuit breaker, or blows a fuse has a subtle effect on the transformer.

Although the transformer may continue to operate as before, repeat occurrences of such damaging electrical events, or lack of even minimal maintenance can greatly accelerate the eventual failure of the transformer.

The fact that a transformer continues to operate satisfactorily in spite of neglect and abuse is a testament to its durability. However, this durability is no excuse for not providing the proper care. Most of the effects of aging, faults, or abuse can be detected and corrected by a comprehensive maintenance, inspection, and testing program.

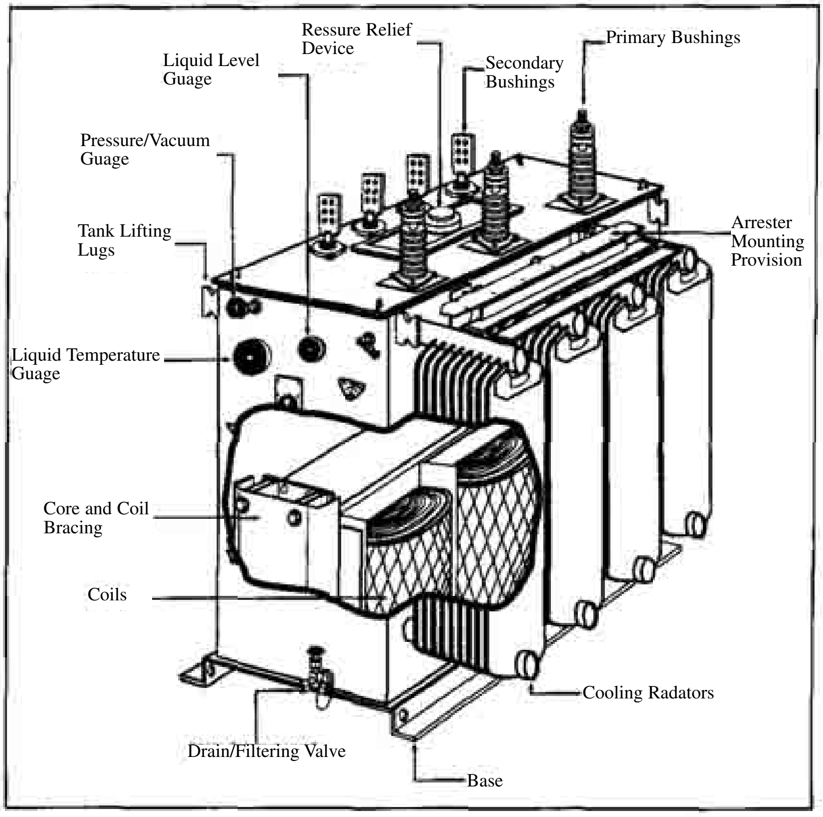


Figure 1-1. Typical power transformer.

1-2. SCOPE

Substation transformers can range from the size of a garbage can to the size of a small house; they can be equipped with a wide array of gauges, bushings, and other types of auxiliary equipment. The basic operating concepts, however, are common to all transformers. An understanding of these basic concepts, along with the application of common sense maintenance practices that apply to other technical fields, will provide the basis for a comprehensive program of inspections, maintenance, and testing. These activities will increase the transformers' service life and help to make the transformer's operation both safe and trouble-free.

1-3. MAINTENANCE AND TESTING

Heat and contamination are the two greatest enemies to the transformer's operation. Heat will break down the solid insulation and accelerate the chemical reactions that take place when the oil is contaminated. All transformers require a cooling method and it is important to ensure that the transformer has proper cooling. Proper cooling usually involves cleaning the cooling surfaces, maximizing ventilation, and monitoring loads to ensure the transformer is not producing excess heat.

a. Contamination is detrimental to the transformer, both inside and out. The importance of basic cleanliness and general housekeeping becomes evident when long-term service life is considered. Dirt buildup and grease deposits severely limit the cooling abilities of radiators and tank surfaces. Terminal and insulation surfaces are especially susceptible to dirt and grease build up. Such buildup will usually affect test results. The transformer's general condition should be noted during any activity, and every effort should be made to maintain its integrity during all operations.

b. The oil in the transformer should be kept as pure as possible. Dirt and moisture will start chemical reactions in the oil that lower both its electrical strength and its cooling capability. Contamination should be the primary concern any time the transformer must be opened. Most transformer oil is contaminated to some degree before it leaves the refinery. It is important to determine how contaminated the oil is and how fast it is degenerating.

Determining the degree of contamination can be accomplished by sampling and analyzing the oil on a regular basis.

c. Although maintenance and work practices are designed to extend the transformer's life, it is inevitable that the transformer will eventually deteriorate to the point that it fails or must be replaced. Transformer testing allows this aging process to be quantified and tracked, to help predict replacement intervals and avoid failures. Historical test data is valuable for determining damage to the transformer after a fault or failure has occurred elsewhere in the circuit. By comparing test data taken after the fault to previous test data, damage to the transformer can be determined.

1-4. SAFETY

Safety is of primary concern when working around a transformer. The substation transformer is usually the highest voltage item in a facility's electrical distribution system. The higher voltages found at the transformer deserve the respect and complete attention of anyone working in the area. A 13.8 kV system will arc to ground over 2 to 3 in. However, to extinguish that same arc will require a separation of 18 in. Therefore, working around energized conductors is not recommended for anyone but the qualified professional. The best way to ensure safety when working around high voltage apparatus is to make absolutely certain that it is deenergized.

a. Although inspections and sampling can usually be performed while the transformer is in service, all other service and testing functions will require that the transformer is de-energized and locked out. This means that a thorough understanding of the transformer's circuit and the disconnecting methods should be reviewed before any work is performed.

b. A properly installed transformer will usually have a means for disconnecting both the primary and the secondary sides; ensure that they are opened before any work is performed. Both disconnects should be opened because it is possible for generator or induced power to backfeed into the secondary and step up into the primary.

After verifying that the circuit is de-energized at the source, the area where the work is to be performed should be checked for voltage with a "hot stick" or some other voltage-indicating device.

c. It is also important to ensure that the circuit stays deenergized until the work is completed. This is especially important when the work area is not in plain view of the disconnect. Red or orange lock-out tags should be applied to all breakers and disconnects that will be opened for a service procedure. The tags should be highly visible, and as many people as possible should be made aware of their presence before the work begins.

d. Some switches are equipped with physical locking devices (a hasp or latch). This is the best method for locking out a switch. The person performing the work should keep the key at all times, and tags should still be applied in case other keys exist.

e. After verifying that all circuits are de-energized, grounds should be connected between all items that could have a different potential. This means that all conductors, hoses, ladders and other equipment should be grounded to the tank, and that the tank's connection to ground should be verified before beginning any work on the transformer. Static charges can be created by many maintenance activities, including cleaning and filtering.

The transformer's inherent ability to step up voltages and currents can create lethal quantities of electricity.

f. The inductive capabilities of the transformer should also be considered when working on a de-energized unit that is close to other conductors or devices that are energized. A de-energized transformer can be affected by these energized items, and dangerous currents or voltages can be induced in the adjacent windings.

g. Most electrical measurements require the application of a potential, and these potentials can be stored, multiplied, and discharged at the wrong time if the proper precautions are not taken. Care should be taken during the tests to ensure that no one comes in contact with the transformer while it is being tested. Set up safety barriers, or appoint safety personnel to secure remote test areas. After a test is completed, grounds should be left on the tested item for twice the duration of the test, preferably longer.

h. Once the operation of the transformer is understood, especially its inherent ability to multiply voltages and currents, then safety practices can be applied and modified for the type of operation or test that is being performed. It is also recommended that anyone working on transformers receive regular training in basic first aid, CPR, and resuscitation.

1-5. NAMEPLATE DATA

The transformer nameplate contains most of the important information that will be needed in the field. The nameplate should never be removed from the transformer and should always be kept clean and legible.

Although other information can be provided, industry standards require that the following information be displayed on the nameplate of all power transformers:

a. Serial number. The serial number is required any time the manufacturer must be contacted for information or parts. It should be recorded on all transformer inspections and tests.

b. Class. The class, as discussed in paragraph 4-1, will indicate the transformer's cooling requirements and increased load capability.

c. The kVA rating. The kVA rating, as opposed to the power output, is a true indication of the current carrying capacity of the transformer. kVA ratings for the various cooling classes should be displayed. For threephase transformers, the kVA rating is the sum of the power in all three legs.

d. Voltage rating. The voltage rating should be given for the primary and secondary, and for all tap positions.

e. Temperature rise. The temperature rise is the allowable temperature change from ambient that the transformer can undergo without incurring damage.

f. Polarity (single phase). The polarity is important when the transformer is to be paralleled or used in conjunction with other transformers.

g. Phasor diagrams. Phasor diagrams will be provided for both the primary and the secondary coils. Phasor diagrams indicate the order in which the three phases will reach their peak voltages, and also the angular displacement (rotation) between the primary and secondary.

h. Connection diagram. The connection diagram will indicate the connections of the various windings, and the winding connections necessary for the various tap voltages.

i. Percent impedance. The impedance percent is the vector sum of the transformer's resistance and reactance expressed in percent. It is the ratio of the voltage required to circulate rated current in the corresponding winding, to the rated voltage of that winding. With the secondary terminals shorted, a very small voltage is required on the primary to circulate rated current on the secondary. The impedance is defined by the ratio of the applied voltage to the rated voltage of the winding.

If, with the secondary terminals shorted, 138 volts are required on the primary to produce rated current flow in the secondary, and if the primary is rated at 13,800 volts, then the impedance is 1 percent. The impedance affects the amount of current flowing through the transformer during short circuit or fault conditions.

j. Impulse level (BIL). The impulse level is the crest value of the impulse voltage the transformer is required to withstand without failure. The impulse level is designed to simulate a lightning strike or voltage surge condition. The impulse level is a withstand rating for extremely short duration surge voltages. Liquid-filled transformers have an inherently higher BIL rating than dry-type transformers of the same kVA rating.

k. Weight. The weight should be expressed for the various parts and the total. Knowledge of the weight is important when moving or untanking the transformer.

l. Insulating fluid. The type of insulating fluid is important when additional fluid must be added or when unserviceable fluid must be disposed of.

Different insulating fluids should never be mixed. The number of gallons, both for the main tank, and for the various compartments should also be noted.

m. Instruction reference. This reference will indicate the manufacturer's publication number for the transformer instruction manual.

CHAPTER 2
CONSTRUCTION/THEORY

2-L. TRANSFORMER APPLICATIONS

A power transformer is a device that changes (transforms) an alternating voltage and current from one level to another. Power transformers are used to "step up" (transform) the voltages that are produced at generators to levels that are suitable for transmission (higher voltage, lower current). Conversely, a transformer is used to "step down" (transform) the higher transmission voltages to levels that are suitable for use at various facilities (lower voltage, higher current). Electric power can undergo numerous transformations between the source and the final end use point (see figure 2-1).

a. Voltages must be stepped-up for transmission. Every conductor, no matter how large, will lose an appreciable amount of power (watts) to its resistance (R) when a current (T) passes through it. This loss is expressed as a function of the applied current (P=I2xR). Because this loss is dependent on the current, and since the power to be transmitted is a function of the applied volts (E) times the amps (P=IxE), significant savings can be obtained by stepping the voltage up to a higher voltage level, with the corresponding reduction of the current value. Whether 100 amps is to be transmitted at 100 volts (P=IxE, 100 amps X 100 volts = 10,000 watts) or 10 amps is to be transmitted at 1,000 volts (P=lxE, 10 amps X 1,000 volts = 10,000 watts) the same 10,000 watts will be applied to the beginning of the transmission line.

b. If the transmission distance is long enough to produce 0.1 ohm of resistance across the transmission cable, P=12R, (100 amp)2 X 0.1 ohm = 1,000 watts will be lost across the transmission line at the 100 volt transmission level. The 1,000 volt transmission level will create a loss of P=12R, (10 amp)2 X 0.1 ohm = 10 watts. This is where transformers play an important role.

c. Although power can be transmitted more efficiently at higher voltage levels, sometimes as high as 500 or 750 thousand volts (kv), the devices and networks at the point of utilization are rarely capable of handling voltages above 32,000 volts. Voltage must be "stepped down" to be utilized by the various devices available.

By adjusting the voltages to the levels necessary for the various end use and distribution levels, electric power can be used both efficiently and safely.

d. All power transformers have three basic parts, a primary winding, secondary winding, and a core. Even though little more than an air space is necessary to insulate an "ideal" transformer, when higher voltages and larger amounts of power are involved, the insulating material becomes an integral part of the transformer's operation. Because of this, the insulation system is often considered the fourth basic part of the transformer. It is important to note that, although the windings and core deteriorate very little with age, the insulation can be subjected to severe stresses and chemical deterioration. The insulation deteriorates at a relatively rapid rate, and its condition ultimately determines the service life of the transformer.

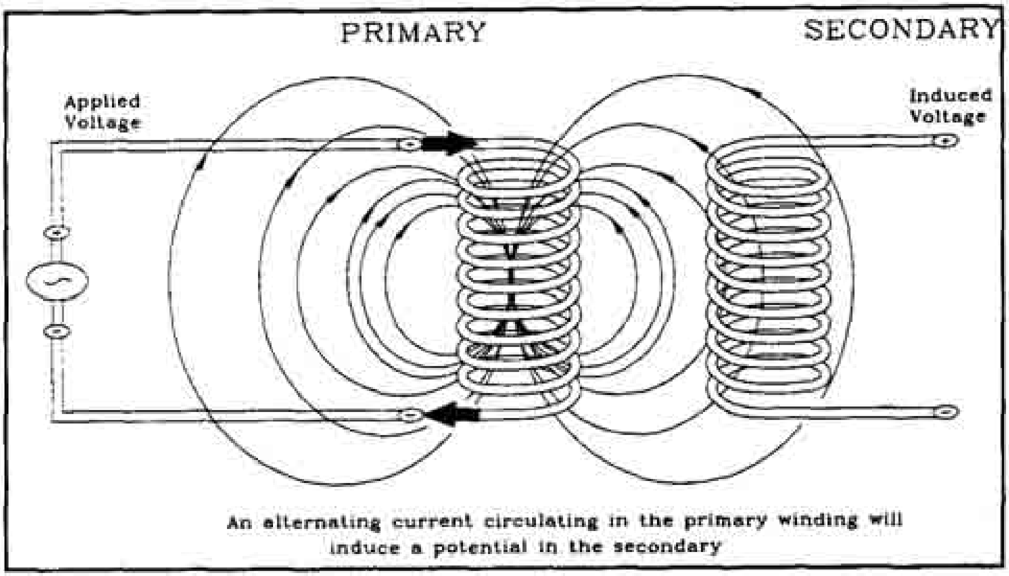

PRIMARY
SECONDARY
Applied Voltage
Induced Voltage
An alternating current circulating in the primary winding will induce a potential in the secondary

Figure 2-1. Distribution system schematic.

2-2. MAGNETIC FLUX

The transformer operates by applying an alternative voltage to the primary winding. As the voltage increases, it creates a strong magnetic field with varying magnetic lines of force (flux lines) that cut across the secondary windings. When these flux lines cut across a conductor, a current is induced in that conductor. As the magnitude of the current in the primary increases, the growing flux lines cut across the secondary winding, and a potential is induced in that winding. This inductive liking and accompanying energy transfer between the two windings is the basis of the transformer's operation (see figure 2-2). The magnetic lines of flux "grow" and expand into the area around the winding as the current increases in the primary. To direct these lines of flux towards the secondary, various core materials are used. Magnetic lines of force, much like electrical currents, tend to take the path of least resistance. The opposition to the passage of flux lines through a material is called reluctance, a characteristic that is similar to resistance in an electrical circuit. When a piece of iron is placed in a magnetic field the lines of force tend to take the path of least resistance (reluctance), and flow through the iron instead of through the surrounding air. It can be said that the air has a greater reluctance than the iron. By using iron as a core material, more of the flux lines can be directed from the primary winding to the secondary winding; this increases the transformer's efficiency.

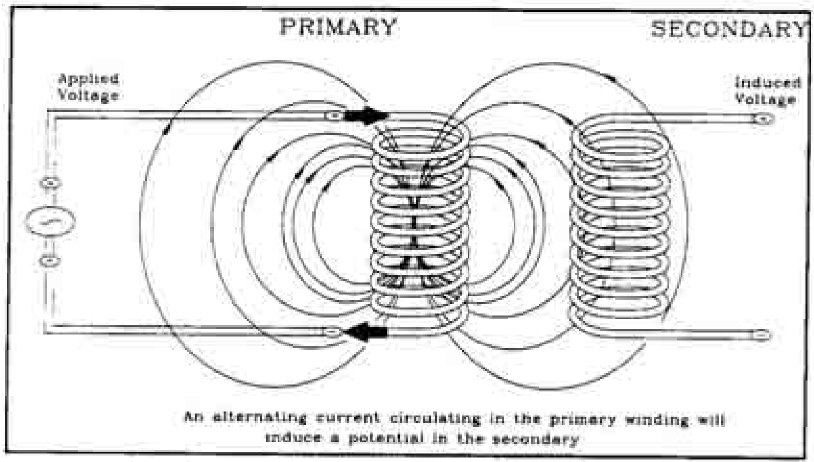

PRIMARY
SECONDARY
Applied Voltage
Induced Voltage
An alternating current circulating in the primary winding will induce a potential in the secondary

Figure 2-2. Transformer flux lines.

2-3. WINDING, CURRENT AND VOLTAGE RATIOS

If the primary and secondary have the same number of turns, the voltage induced into the secondary will be the same as the voltage impressed on the primary (see figure 2-3).

a. If the primary has more turns than the secondary then the voltage induced in the secondary windings will be stepped down in the same ratio as the number of turns in the two windings. If the primary voltage is 120 volts, and there are 100 turns in the primary and 10 turns in the secondary, then the secondary voltage will be 12 volts. This would be termed a "step down" transformer as shown in figure 2-4.

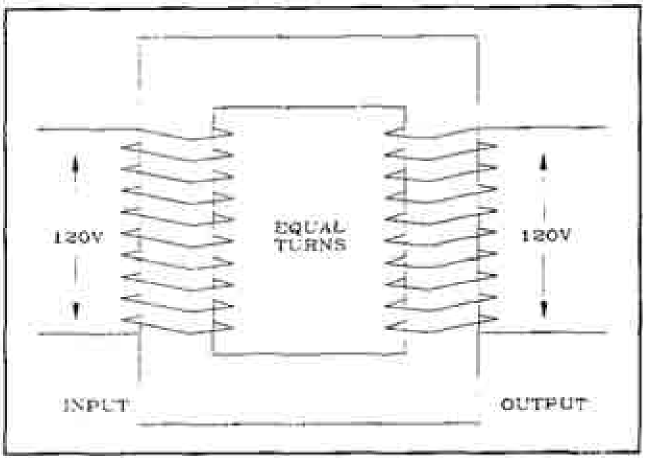


Figure 2-3. Transformer equal turns ratio

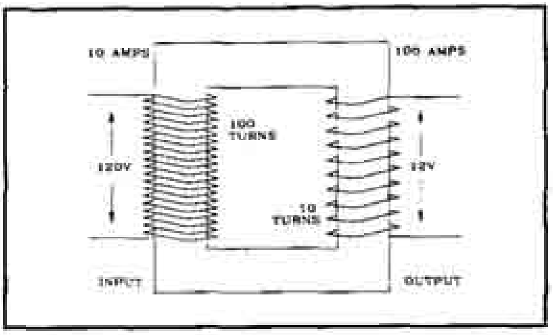


Figure 2-4. Transformer 10:1 turns ratio

b. A "step up" transformer would have more turns on the secondary than on the primary, and the reverse voltage relationship would hold true. If the voltage on the primary is 120 volts, and there are 10 turns in the primary and 100 turns in the secondary, then the secondary voltage would be 1200 volts. The relationship between the number of turns on the primary and secondary and the input and output voltages on a step up transformer is shown in figure 5-2.

c. Transfomers are used to adjust voltages and currents to the level required for specific applications. A transformer does not create power, and therefore ignoring losses, the power into the transformer must equal the power out of the transformer. This means that, according to the previous voltage equations, if the voltage is stepped up, the current must be stepped down. Current is transformed in inverse proportion to the ratio of turns, as shown in the following equations:

$$\frac{N_p \text{ (turns on primary)}}{N_s \text{ (turns on secondary)}} = \frac{I_s \text{ (amperes in secondary)}}{I_p \text{ (amperes in primary)}}$$

$$\frac{E_p \text{ (volts primary)}}{E_s \text{ (volts secondary)}} = \frac{I_s \text{ (amperes secondary)}}{I_p \text{ (amperes primary)}}$$

d. The amount of power that a transformer can handle is limited by the size of the winding conductors, and by the corresponding amount of heat they will product when current is applied. This heat is caused by losses, which results in a difference between the input and output power. Because of these losses, and because they are a function of the impedance rather than pure resistance, transformers are rated not in terms of power (Watts), but in terms of kVA. The output voltage is multiplied by the output current to obtain volt-amps; the k designation represents thousands.

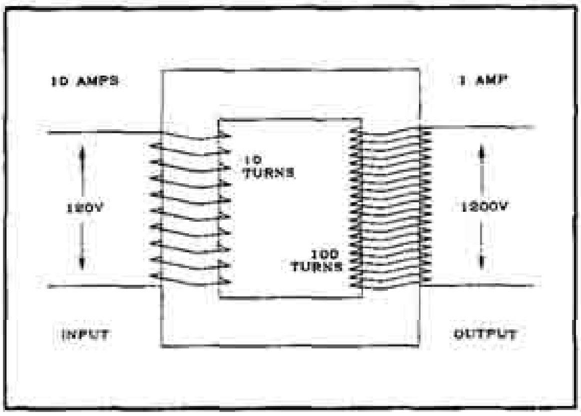


Figure 2-5. Transformer 1:10 turns ratio

2-4. CORE CONSTRUCTION

To reduce losses, most transformer cores are made up of thin sheets of specially annealed and rolled silicone steel laminations that are insulated from each, other. The molecules of the steel have a crystal structure that tends to direct the flux. By rolling the steel into sheets, it is possible to "orient" this structure to increase its ability to carry the flux.

a. As the magnetic flux "cuts" through the core materials, small currents called "eddy currents" are induced. As in any other electrical circuit, introducing resistance (for example, insulation between the laminations), will reduce this current and the accompanying losses. If a solid piece of material were used for the core, the currents would be too high. The actual thickness of the laminations is determined by the cost to produce thinner laminations versus the losses obtained. Most transformers operating at 60 Hertz (cycles per second) have a lamination thickness between 0.01 and 0.02 in. Higher frequencies require thinner laminations.

b. The laminations must be carefully cut and assembled to provide a smooth surface around which the windings are wrapped. Any burrs or pointed edges would allow the flux lies to concentrate, discharge and escape from the core. The laminations are usually clamped and blocked into place because bolting would interrupt the flow of flux. Bolts also have a tendency to loosen when subjected to the vibrations that are found in a 60-cycle transformer's core. It is important that this clamping arrangement remains tight; any sudden increase in noise or vibration of the transformer can indicate a loosening of the core structure.

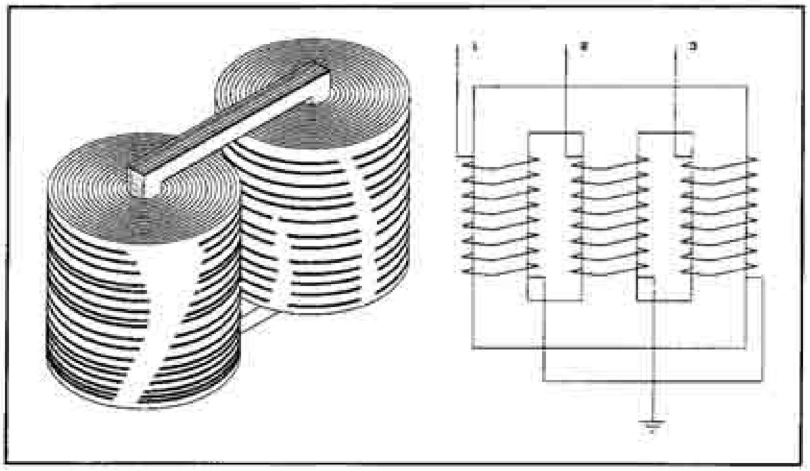


Figure 2-6. Transformer shell construction.

2-5. CORE FORM CONSTRUCTION

There are two basic types of core assembly, core form and shell form. In the core form, the windings are wrapped around the core, and the only return path for the flux is through the center of the core. Since the core is located entirely inside the windings, it adds a little to the structural integrity of the transformer's frame. Core construction is desirable when compactness is a major requirement. Figure 2-6 illustrates a number of core type configurations for both single and multi-phase transformers.

2-6. SHELL FORM CONSTRUCTION

Shell form transformers completely enclose the windings inside the core assembly. Shell construction is used for larger transformers, although some core-type units are built for medium- and high-capacity use. The core of a shell type transformer completely surrounds the windings, providing a return path for the flux lines both through the center and around the outside of the windings (see figure 2-7). Shell construction is also more flexible, because it allows a wide choice of winding arrangements and coil groupings. The core can also act as a structural member, reducing the amount of external clamping and bracing required. This is especially important in larger application where large forces are created by the flux.

a. Certain wiring configurations of shell form transformers, because of the multiple paths available for the flux flow are susceptible to higher core losses due to harmonic generations. As the voltage rises and falls at the operating frequency, the inductance and capacitance of various items in or near the circuit operate at a frequency similar to a multiple of the operating frequency.

The "Third Harmonic" flows primarily in the core, and can triple the core losses. These losses occur primarily in Wye-Wye configured transformers.

b. The flux that links the two windings of the transformer together also creates a force that tends to push the conductors apart. One component of this force, the axial component, tends to push the coils up and down on the core legs, and the tendency is for the coils to slide up and over each other. The other component is the longitudinal force, where the adjacent coils push each other outward, from side to side. Under normal conditions, these forces are small, but under short circuit conditions, the forces can multiply to hundreds of times the normal value. For this reason, the entire coil and winding assembly must be firmly braced, both on the top and bottom and all around the sides. Bracing also helps to hold the coils in place during shipping.

c. The bracing also maintains the separation that is a necessary part of the winding insulation, both from the tank walls, and from the adjacent windings.

Nonconductive materials, such as plastic, hardwood or plywood blocks are used to separate the windings from each other and from the tank walls. These separations in the construction allow paths for fluid or air to circulate, both adding to the insulation strength, and helping to dissipate the heat thereby cooling the windings. This is especially important in large, high-voltage transformers, where the heat buildup and turn-to-turn separations must be controlled.

d. The windings of the transformer most be separated (insulated) from each other and from the core, tank, or other grounded material. The actual insulation between the turns of each winding can usually be provided by a thin enamel coating or a few layers of paper.

This is because the entire voltage drop across the windings is distributed proportionately across each turn. In other words, if the total voltage drop across a winding is 120 volts, and there are 100 turns in that winding, the potential difference between each turn is 1.2 volts (120/100).

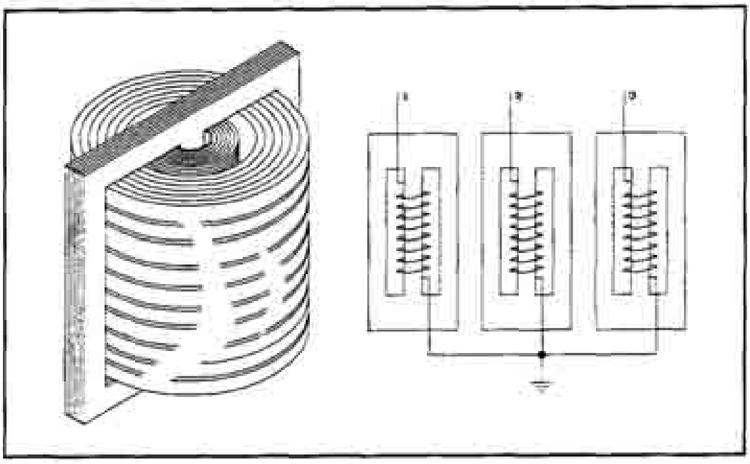


Figure 2-7. Transformer shell construction.

e. Transformers are designed to withstand impulse levels several times, and in some cases, hundreds of times higher than one operating voltage. This is to provide adequate protection in the case of a lightning strike, a switching surge or a short circuit. By allowing oil to circulate between the windings, the turn-to-turn insulating level can be appreciably increased and the amount of heat built up in the windings can be efficiently dissipated.

f. Most large power transformers have their windings immersed in some type of fluid. Although larger dry type transformers are constantly being produced, and many new forms of construction, such as resin cast and gas filled, are being used for power applications, the most common method of insulating the windings and dissipating the heat is by submerging the windings and core in an insulating fluid. Silicone, trichloroethane, and a wide variety of low tie point hydrocarbon based fluids are just a few of the fluids currently in use. This manual primarily applies to mineral oil-filled transformers.

Although there are similarities between mineral oil and many other fluids being used, the manufacturer's specifications and instructions for each fluid should always be considered. Any reference in this manual to insulating, unless otherwise stated, will be implied to mean mineral oil.

g. Heat must be dissipated by fluid because no transformer is 100 percent efficient. There are many forms of losses in a transformer, and although they have different sources, the resultant product of these losses is heat build up within the tank. Transformer losses can be divided into two general categories, load losses and no-load losses. No-load losses are independent of the applied load, and include core losses, excitation losses, and dielectric losses in the insulation. Load loses consist of the copper losses across the windings that are produced by the applied current (12R), and of the stray currents in the windings that appear when the load is applied. These loses are usually listed by the manufacturer for each type of transformer. They are especially important when considering the cooling requirements of the transformer

h. Some of the important transformer equations are as follows:

Basic transformer ratio:

$$\frac{N_p \text{ (\# turns primary)}}{N_s \text{ (\# turns secondary)}} = \frac{E_p \text{ (volts primary)}}{E_s \text{ (volts secondary)}}$$

Current equation:

$$I_p \times N_p = I_s \times N_s$$

Percent efficiency:

$$\frac{\text{output} \times 100\%}{\text{input}} = \frac{\text{output} \times 100\%}{\text{output} + \text{losses}}$$

CHAPTER 3
TRANSFORMER CONNECTIONS AND TAPS

3-1. TAPPED PRIMARIES AND SECONDARIES

To composite for changing input voltages, multiple connections or "taps" are provided to allow different portions of the winding to be used. When the taps are connected on the primary winding, the turn-to-turn ratio is changed, and the required secondary voltage can be obtained in spite of a change in source voltage. Manufacturers usually provide taps at 2-1/2 percent intervals above and below the rated voltage (see figure 3-1). Taps at 2.5 percent allow the number of turns on the primary to change.

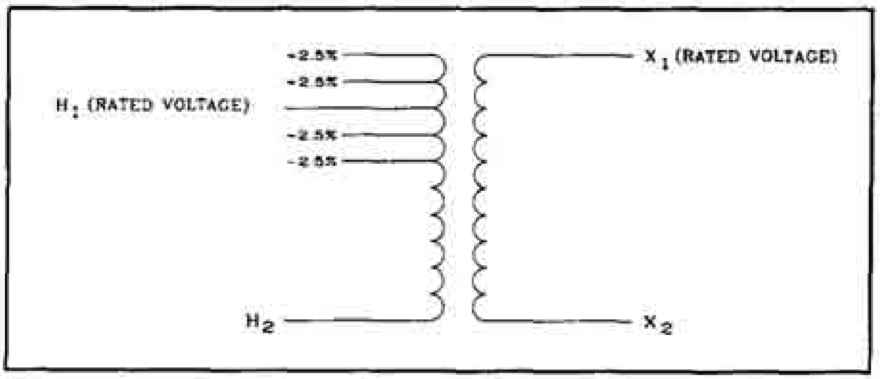


Figure 3-1. Transformer taps.

a. Taps are usually changed by turning a crank or handwheel, although some transformers require that a cover be removed and the actual tiding leads be connected on a terminal board where all of the taps can be accessed. Tap changers can be either "Load Tap Changing" or "No-Load Tap (N.L.T.) Changing" units, although most of them must be changed with the transformer de-energized.

b. Smaller single-phase transformers are usually provided with center-tapped secondaries, with the leads brought out from both halves of the tapped winding.

When the center tap leads are connected together, that winding becomes one continuous coil, and it is said to be connected in series (see figure 3-2). Because the maximum number of turns are used, the maximum voltage is obtained, at the corresponding current level.

e. When the center taps are connected to the opposite output leads, the winding becomes two separate windings working in parallel (see figure 3-2). A lower voltage at a corresponding higher current level is obtained.

3-2. POLARITY

Note that, when the center tap is connected in parallel, both windings are oriented in the same direction with respect to the primary. The clockwise or counterclockwise direction that the windings are wound on the core determine the direction of the current flow (the right-hand rule). This relationship of winding orientation to current flow in the transformer is known as polarity.

a. The polarity of a transformer is a result of the relative winding directions of the transformer primary conductor with respect to the transformer secondary (see figure 3-3). Polarity is a function of the transformer's construction. Polarity becomes important when more than one transformer is involved in a circuit.

Therefore, the polarities and markings of transformers are standardized. Distribution Transformers above 200 KVA or above 860 volts are "subtractive."

b. Transformer polarity is an indication of the direction of current flow through the high-voltage terminals, with respect to the direction of current flow through the low-voltage terminals at any given instant in the alternating cycle. Transformers are constructed with additive or subtractive polarity (see figures 3-4). The terminal markings on transformers are standardized among the various manufacturers, and are indicative of the polarity. However, since there is always the possibility that the wiring of a transformer could have been changed, it is important to check the transformer's polarity before making any wiring changes.

c. The polarity is subtractive when the high-side lead (Hl) is brought out on the same side as the low-side lead (Xl). If a voltage is placed on the high-side, and a jumper is connected between the Hl and Xl terminals (see figure 3-5), the voltage read across the H2 and X2 terminals will be less than the applied voltage. Most large power transformers were constructed with subtractive polarity.

d. When the high-side lead (Hl) is brought out on the opposite side of the low-side lead (Xl) and is on the same side as the low side lead (X2), the polarity is additive.

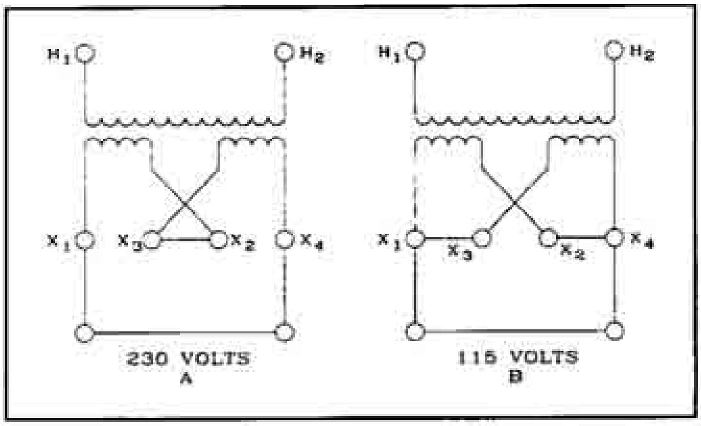


Figure 3-2. Single phase transformer secondary winding arrangements.

If a voltage is placed across the high-side, and a jumper is connected between the Hl and X2 terminals, the voltage read across the HZ and Xl terminals will be greater than the applied voltage (see figure 3-6).

3-3. AUTOTRANSFORMERS

Although the examples illustrated up to this point have used two separate windings to transform the voltage and current, this transformation can be accomplished by dividing one winding into sections. The desired ratio can be obtained by "tapping" the winding at a prescribed point to yield the proper ratio between the two sections. This arrangement is called an "Autotransformer."

a. Even though the winding is continuous, the desired voltages and currents can be obtained.

Although an autotransformer is made up of one continuous winding, the relationship of the two sections can be more readily understood lf they are thought of as two separate windings connected in series. Figure 3-7 shows the current and voltage relationships in the variable sections of an autotransformer.

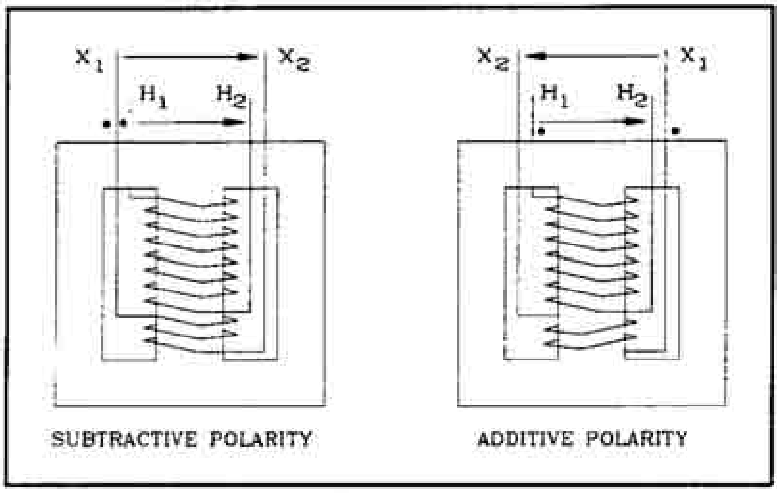


Figure 3-3. Physical transformer polarity.

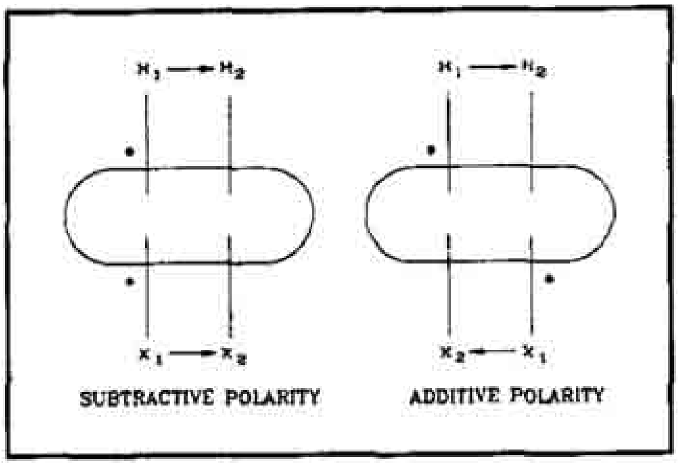


Figure 3-4. Diagrammatic transformer polarity.

b. Autotransformers are inherently smaller than normal two-winding transformers. They are especially suited for applications where there is not too much difference between the primary and secondary voltages (transformer ratios usually less than 5:l). An autotransformer will have lower losses, impedance, and excitation current values than a two-winding transformer of the same KVA rating because less material is used in its construction.

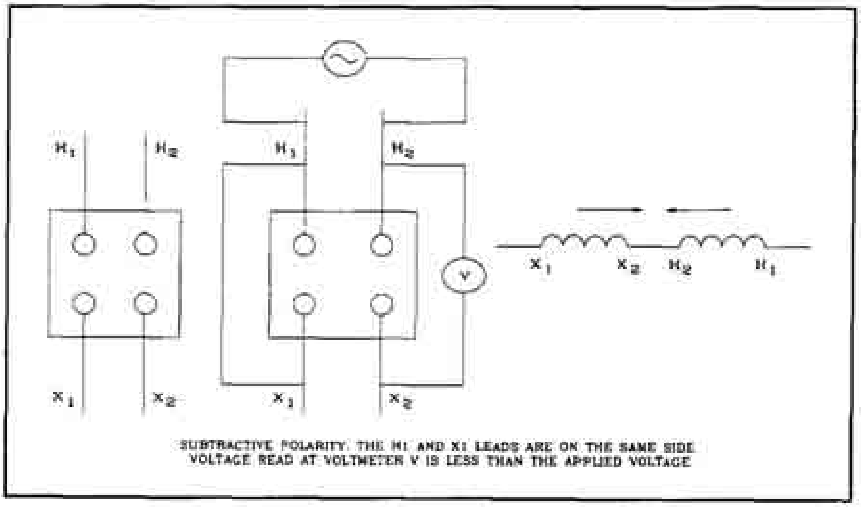

H1
H2
H1
H2
V
X1
X2
X1
X2
X1
X2
H2
H1
SUBTRACTIVE POLARITY. THE H1 AND X1 LEADS ARE ON THE SAME SIDE
VOLTAGE READ AT VOLTMETER V IS LESS THAN THE APPLIED VOLTAGE

Figure 3-5. Transformer subtractive polarity test.

c. The major drawback of autotransformers is that they do not provide separation between the primary and secondary. This non-insulating feature of the autotransformer should always be remembered; even though a low voltage may be tapped from an autotransformer, the low voltage circuit must be insulated to the same degree as the high voltage side of the transformer.

Another drawback is that the autotransformer's impedance is extremely low, and it provides almost no opposition to fault current. Autotransformers are usually primarily for motor staring circuits, where lower voltages are required at the start to reduce the amount of inrush current, and higher voltages are used once the motor is running. Autotransformers are used in power applications where the difference between the primary and secondary voltages is not too great.

3-4. SINGLE AND MULTI-PHASE RELATIONSHIPS

All transformations occur on a single-phase basis; three-phase transformers are constructed by combining three single-phase transformers in the same tank.

As indicated by its name, a single-phase transformer is a transformer that transforms one single-phase voltage and current to another voltage and current levels.

a. Alternating current single-phase power can be represented by a graph of constantly changing voltage versus time (a sine wave). The potential changes continuously from positive to negative values over a given time period. When the voltage has gone through one complete series of positive and negative changes, it is said to have completed one cycle. This cycle is expressed in degrees of rotation, with 360 degrees representing one full cycle. As shown in figure 3-8 a start point is designated for any sine wave. The sine wave position and corresponding voltage can be expressed in degrees of rotation, or degrees of displacement from the starting point.

b. This alternating voltage can be readily produced by rotating generators and, in turn, can be easily utilized by motors and other forms of rotating machinery. Single-phase power is used primarily in residential or limited commercial applications.

c. Most industrial or institutional systems utilize a three-phase power configuration. Three single-phase lines are used (A, B and C), and it is only when they are connected to an end use device, such as a motor or transformer that their relationships to each other become important. By convention, the individual phases of a three-phase distribution system are displaced 120 degrees (one third of a cycle) apart (see figure 3-9).

d. Rather than draw sine waves to show the position of the phases, the relative angular displacement (degrees ahead of or later than) is depicted by phasor diagrams. Phasor diagrams are convenient because they not only show the angular displacement, but they also show how the phases are physically connected.

Transformer manufacturers use phasor diagrams on the nameplate of the transformer to indicate the connections and angular displacement of the primary and secondary phases (see figure 3-10). The polarity of three-phase transformers is determined both by where the leads are brought out of the transformer, and by the connection of the phases inside the tank. The two most common connections for three-phase transformers are delta and wye (star).

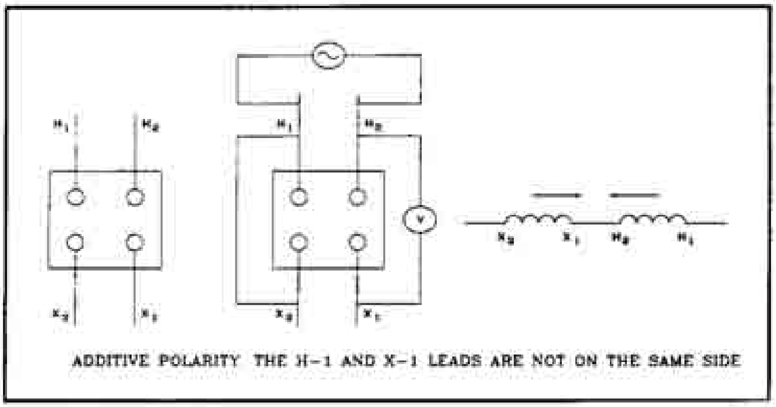
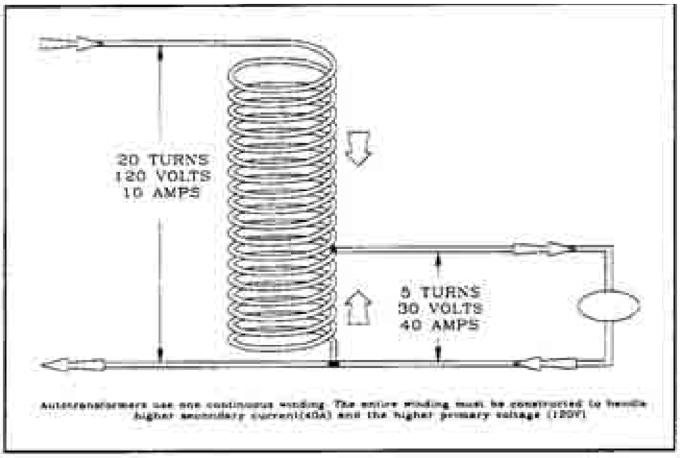

H1
H2
H1
H2
V
X2
X1
X2
X1
X2
X1
H2
H1
ADDITIVE POLARITY THE H-1 AND X-1 LEADS ARE NOT ON THE SAME SIDE

Figure 3-6. Transformer additive polarity test.

e. Delta and wye are the connections and relations of the separate phase on either the primary or the secondary windings. The basic three-phase transformer primary-to-secondary configurations are as follows:

-Delta-delta
-Wye-wye
-Delta-wye
-Wye-delta

f. These configurations can be obtained by connecting together three single-phase transformers or by combining three single-phase transformers in the same tank. There are many variations to these configurations, and the individual transformer's design and application criteria should be considered.



Autotransformers use one continuous winding. The entire winding must be constructed to handle higher secondary current(40A) and the higher primary voltage (120V)

Figure 3-7. Autotransformer.

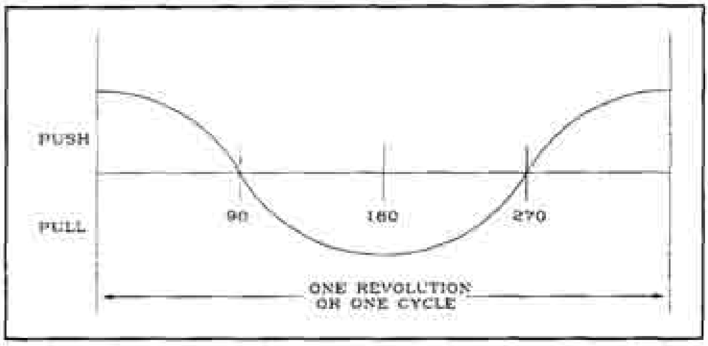


Figure 3-8. Sine wave.

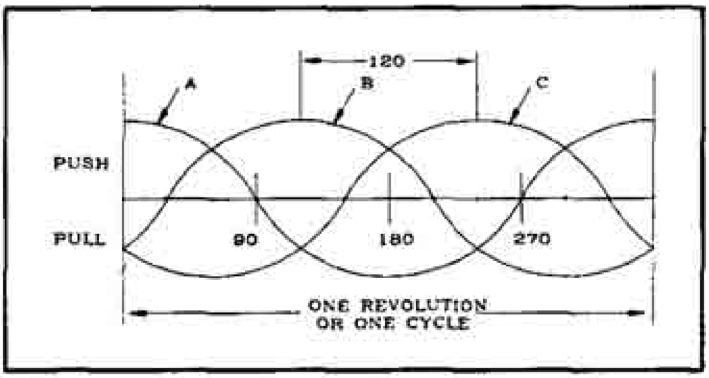


Figure 3-9. Three phase sine waves.

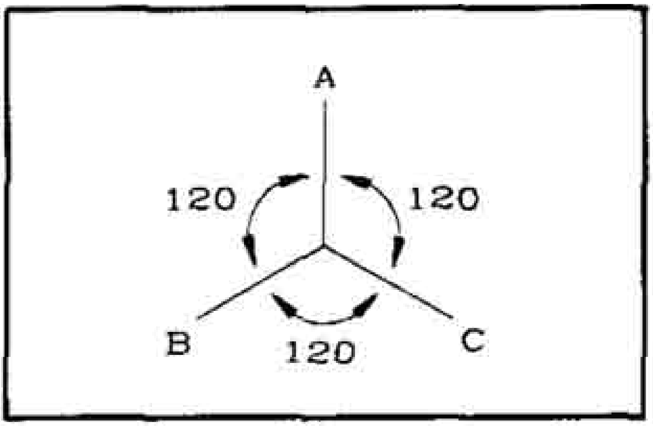


Figure 3-10. Three phase phasor diagram.

g. The wye connection is extremely popular for use on the secondary of substation transformers. By connecting the loads either phase-to-phase or phase-to-neutral, two secondary voltages can be obtained on the secondary. A common secondary voltage on many distribution transformers is 208/120V, with the 208V (phase-to-phase) connections being used to supply motors, and the 120V (phase-to-neutral) connections being used to supply lighting loads (see figure 3-U).

These secondary voltages are related by the square root of three (1.73). As shown in figure 3-11, this configuration provides an added degree of flexibility.

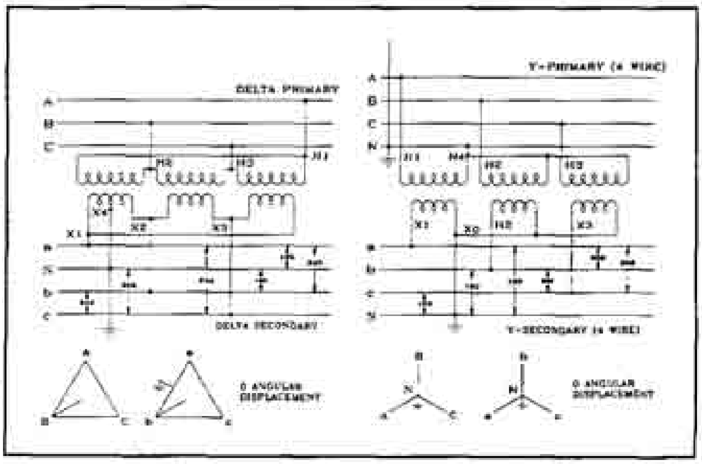


Figure 3-11. Delta-delta and wye-wye transformer configurations.

h. Often, when ground fault is desired for certain circuits, the neutral will be isolated and carried throughout the circuit (except at the system ground point, usually the wye-grounded secondary transformer connection) providing an isolated return path for load currents. This provides an opportunity to monitor these currents and to open the circuit in the event of a ground fault. Although the neutral is eventually grounded, it is isolated for the portion of the circuit where ground fault protection is needed (usually in the switchgear between the transformer secondary and the individual circuit breakers). It is important in these configurations to maintain the isolation of the neutral conductor. The common practice of bonding neutrals to ground at every possible point can defeat this protective scheme and render ground fault protection inoperative.

i. When the neutral conductor is grounded, it provides a stabilizing effect on the circuit. With the neutral point solidly grounded, the voltage of any system conductor, with respect to ground, cannot exceed the phase-to-phase voltage. Without grounding the neutral, any stable ground fault on one line raises the voltage of the two remaining lines with respect to ground, to a point as high as the phase-to-phase voltage. The implications are obvious: there will be less stress placed on the system insulation components with the wye-grounded connection.

3-5. DELTA-WYE AND WYE-DELTA DISPLACEMENTS

As current and voltage are transformed in the individual phases of a wye-delta or delta-wye transformer, they can also have an angular displacement that occurs between the primary and secondary windings. That is, the primary wave-form of the A phase at any given instant is always 30 degrees ahead of or displaced from the wave form of the A phase on the secondary. This 30 degree shift occurs only between the primary and secondary and is independent of the 120 degrees of displacement between the other phases.

a. By convention, delta-delta and wye-wye transformers have zero degrees angular displacement between primary and secondary. See the phasor diagrams in figure 3-11. The individual wave forms between the primary and secondary are identical at any given instant. Delta-wye and wye-delta transformers have an angular displacement of 30 degrees. For these types of connections, the high-voltage reference phase angle side of the transformer is 30 degrees ahead of the low-voltage reference phase angle at any given instant for each individual phase. This displacement is represented on the transformer's nameplate by a rotation of the phasor diagrams between the primary and secondary. See the phasor diagrams in figure 3-12.

b. Most manufacturers conform to American National Standards Institute (ANSI) Standard C57.12.70, "Terminal markings for Distribution and Power Transformers (R1993), for the lead markings of larger (subtractive polarity) three-phase power transformers.

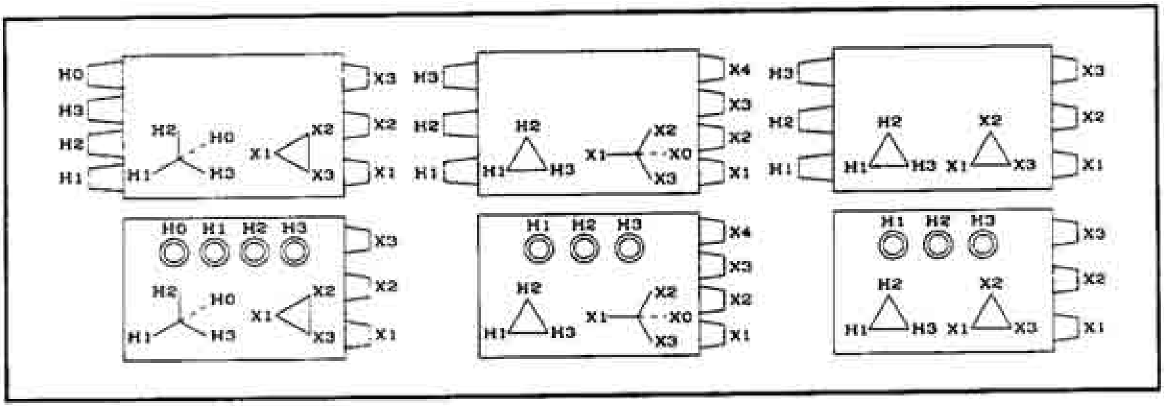


Figure 3-13. Transformer lead markings.

The high-voltage lead, H1 is brought out on the right side when facing the high-voltage side of the transformer case. The remaining high-voltage leads H2 and H3 are brought out and numbered in sequence from right to left. The low-voltage lead, X1 is brought out on the left side (directly opposite the H1 terminal) when facing the low side of the transformer. The remaining leads, X2 and X3 are numbered in sequence from left to right (see figure 3-13). It is important to note that these are suggested applications, and design constraints can require that a transformer be built with different markings. It is also important to remember that in many existing installations, there is the possibility that the leads have been changed and do not conform to the standardized markings.

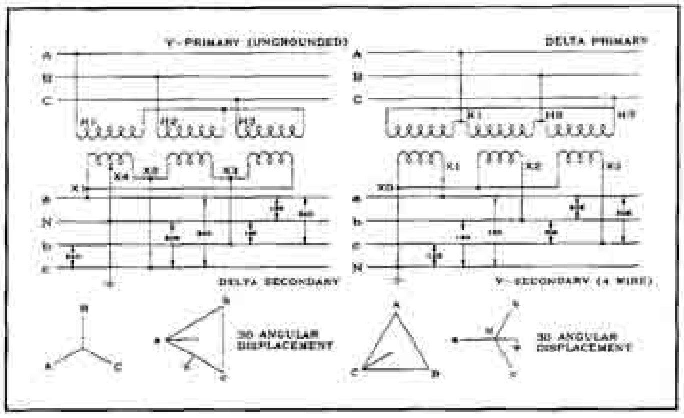
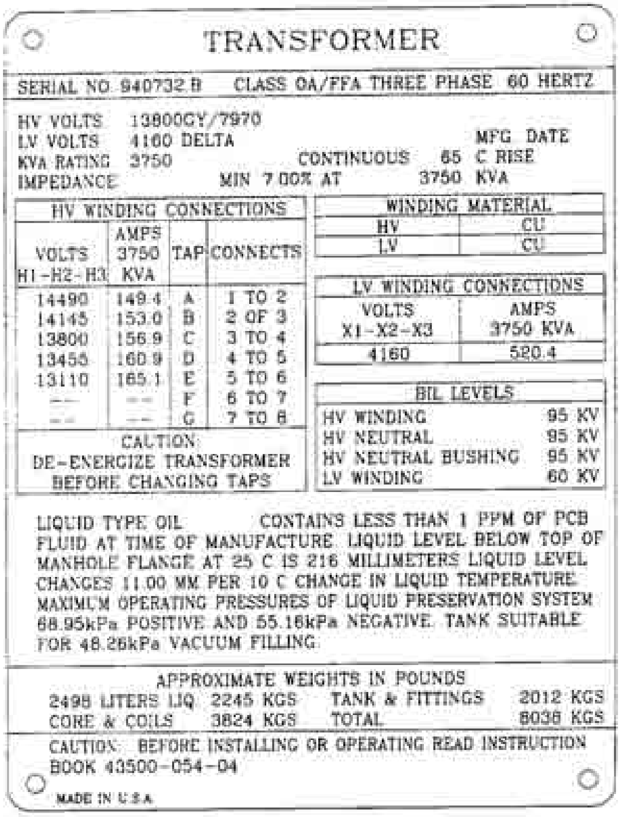


Figure 3-12. Wye-delta and delta-wye transformer configuration.

c. Figure 3-14 shows the standard delta-wye three-phase transformer's nameplate illustrating many of the topics covered in this chapter. The various primary tap voltages, along with the numbered connection points on the actual windings are referenced in the "Connections" table. The wiring diagram shows the relationship and connections of the individual windings, while the phasor diagrams show the phase angle relationship between the individual phases, and between the primary and secondary. Note also that the temperature requirements, the tank pressure capabilities, and the expansion and contraction-versus-temperature values are spelled out.



TRANSFORMER

SERIAL NO 940732 B   CLASS OA/FFA THREE PHASE 60 HERTZ

HV VOLTS 13800GY/7970
LV VOLTS 4160 DELTA   MFG DATE
KVA RATING 3750   CONTINUOUS 65 C RISE
IMPEDANCE   MIN 7.00% AT 3750 KVA

HV WINDING CONNECTIONS			
VOLTS H1-H2-H3	AMPS 3750 KVA	TAP	CONNECTS
14490	149.4	A	1 TO 2
14145	153.0	B	2 OF 3
13800	156.9	C	3 TO 4
13455	160.9	D	4 TO 5
13110	165.1	E	5 TO 6
--	--	F	6 TO 7
--	--	G	7 TO 8

CAUTION
DE-ENERGIZE TRANSFORMER
BEFORE CHANGING TAPS

WINDING MATERIAL	
HV	CU
LV	CU

LV WINDING CONNECTIONS	
VOLTS X1-X2-X3	AMPS 3750 KVA
4160	520.4

BIL LEVELS	
HV WINDING	95 KV
HV NEUTRAL	95 KV
HV NEUTRAL BUSHING	95 KV
LV WINDING	60 KV

LIQUID TYPE OIL   CONTAINS LESS THAN 1 PPM OF PCB FLUID AT TIME OF MANUFACTURE. LIQUID LEVEL BELOW TOP OF MANHOLE FLANGE AT 25 C IS 216 MILLIMETERS LIQUID LEVEL CHANGES 11.00 MM PER 10 C CHANGE IN LIQUID TEMPERATURE. MAXIMUM OPERATING PRESSURES OF LIQUID PRESERVATION SYSTEM 68.95kPa POSITIVE AND 55.16kPa NEGATIVE. TANK SUITABLE FOR 48.26kPa VACUUM FILLING.

APPROXIMATE WEIGHTS IN POUNDS
2498 LITERS LIQ 2245 KGS   TANK & FITTINGS 2012 KGS
CORE & COILS 3824 KGS   TOTAL 8036 KGS

CAUTION: BEFORE INSTALLING OR OPERATING READ INSTRUCTION BOOK 43500-054-04

MADE IN U.S.A.

Figure 3-14. Wye delta transformer nameplate.

CHAPTER 4
COOLING/CONSTRUCTION CLASSIFICATIONS

4-L. CLASSIFICATIONS

Although transformers can be classified by core construction (shell or core type), the more functional types of standardized classifications are based on how the transformer is designed for its specific application, and how the heat created by its losses is dissipated. There are several types of insulating media available. Two basic classifications for insulating media are m-type and liquid filled.

4-2. DRY-TYPE TRANSFORMERS

Dry-type transformers depend primarily on air circulation to draw away the heat generated by the transformer's losses. Air has a relatively low thermal capacity

When a volume of air is passed over an object that has a higher temperature, only a small amount of that object's heat can be transferred to the air and drawn away. Liquids, on the other hand, are capable of drawing away larger amounts of heat. Air-cooled transformers, although operated at higher temperatures, are not capable of shedding heat as effectively as liquid cooled transforms. This is further complicated by the inherent inefficiency of the dry-type transformer. Transformer oils and other synthetic transformer fluids are capable of drawing away larger quantities of excess heat.

a. Dry-type transformers are especially suited for a number of applications. Because dry-type transformers have no oil, they can be used where fire hazards must be minimized. However, because dry-type transformers depend on air to provide cooling, and because their losses are usually higher, there is an upper limit to their size (usually around 10,000 kVA, although larger ones are constantly being designed). Also, because oil is not available to increase the dielectric strength of the insulation, more insulation is required on the windings, and they must be wound with more clearance between the individual turns.

b. Dry-type transformers can be designed to operate at much higher temperatures than oil-filled transformers (temperature rises as high as 150 degrees Celsius). Although oil is capable of drawing away larger amounts of heat, the actual oil temperature must be kept below approximately 100 degrees Celsius to prevent accelerated breakdown of the oil.

c. Because of the insulating materials used (glass, paper, epoxy, etc.) and the use of air as the cooling medium, the operating temperatures of dry-type transformers are inherently higher. It is important that adequate ventilation be provided. A good rule of thumb is to provide at least 20 square feet of inlet and outlet ventilation in the room or vault for each 1,000 kVA of transformer capacity. If the transformer's losses are known, an air volume of 100 cfm (cubic feet per minute) for each kW of loss generated by the transformer should be provided. Dry-type transformers can be either self-cooled or forced-air cooled.

d. A self-cooled dry-type transformer is cooled by the natural circulation of air through the transformer case. The cooling class designation for this transformer is AA. This type of transformer depends on the convection currents created by the heat of the transformer to create an airflow across the coils of the transformer.

e. Often, fans will be used to add to the circulation of air through the case. Louvers or screened openings are used to direct the flow of cool air across the transformer coils. The kVA rating of a fan-cooled dry-type transformer is increased by as much as 33 percent over that of a self-cooled dry-type of the same design. The cooling class designation for fan cooled or air blast transformers is FA. Dry-type transformers can be obtained with both self-cooled and forced air-cooled ratings. The designation for this type of transformers is AA/FA.

f. Many other types of dry-type transformers are in use, and newer designs are constantly being developed.

Filling the tank with various types of inert gas or casting the entire core assemblies in epoxy resins are just a few of the methods currently is use. Two of the advantages of dry-type transformers are that they have no fluid to leak or degenerate over time, and that they present practically no fire hazard. It is important to remember that dry-type transformers depend primarily on their surface area to conduct the heat away from the core.

Although they require less maintenance, the core and case materials must be kept clean. A thin layer of dust or grease can act as an insulating blanket, and severely reduce the transformer's ability to shed its heat.

4-3. LIQUID-FILLED TRANSFORMERS

Liquid-filled transformers are capable of handling larger amounts of power. The liquid (oil, silicone, PCB etc.) transfers the heat away from the core more effectively than air. The liquid can also be routed away from the main tank, into radiators or heat exchangers to further increase the cooling capacity. Along with cooling the transformer, the liquid also acts as an insulator. Since oils and synthetics will break down and lose their insulating ability at higher temperatures, liquid filled transformers are designed to operate at lower temperatures than dry-types (temperature rises around 55 degrees Celsius). Just as with dry-types, liquid-filled transformers can be self-cooled, or they can use external systems to augment the cooling capacity.

a. A self-cooled transformer depends on the surface area of the tank walls to conduct away the excess heat.

This surface area can be increased by corrugating the tank wall, adding fins, external tubing or radiators for the fluid. The varying heat inside the tank creates convection currents in the liquid, and the circulating liquid draws the heat away from the core. The cooling class designation for self-cooled, oil-filled transformers is OA.

b. Fans are often used to help circulate the air around the radiators. These fans can be manually or automatically controlled, and wiIl increase the transformer's kVA capacity by varying amounts, depending on the type of construction. The increase is usually around 33 percent, and is denoted on the transformer's nameplate by a slash (/) rating. Slash ratings are determined by the manufacturer, and vary for different transformers. If loading is to be increased by the addition of pumps or fans, the manufacturer should be contacted. The cooling class designation for a forced air-cooled, oil-filled transformer is OA/FA.

c. Pumps can be used to circulate the oil in the tank and increase the cooling capacity. Although the convection currents occur in the tank naturally, moving the oil more rapidly past the radiators and other heat exchangers can greatly increase their efficiency. The pumps are usually installed where the radiators join the tank walls, and they are almost always used in conjunction with fans. The cooling class designation for forced oil and forced air cooled transformers is OA/FA/FOA.

d. To obtain improved cooling characteristics, an auxiliary tubing system is often used to circulate water through the transformer's oil. This type of design is especially suited for applications where sufficient air circulation cannot be provided at the point of installation, such as underground, inside of buildings, or for specialized applications in furnace areas. Because water is used to draw off the heat, it can be piped to a remote location where heat exchangers can be used to dissipate the heat. In this type of construction, tubing is used to circulate water inside the tank. The tubing circulates through the oil near the top, where it is the hottest; great pains must be taken to ensure that the tubing does not leak, and to allow the water to mix with the oil. Water is especially desirable for this application because it has a higher thermal capacity than oil. If untreated water is used, steps must be taken to ensure that the pipes do not become clogged by contaminants, especially when hard water is used. The cooling class designation for water-cooled transformers is FOW.

4-4. TANK CONSTRUCTION

Transformers can also be classified according to tank construction. Although the ideal transformer is a static device with no moving parts, the oil and the tank itself are constantly expanding and contracting, or "breathing", according to the changing temperatures caused by the varying load of the transformer.

a. When the oil is heated, it expands (0.08 percent volume per degree Celsius) and attempts to force air out of the tank. Thermal expansion can cause the oil level in the tank to change as much as 5 or 6 inches, depending on the type of construction. This exhaust cycle causes no harm. It is on the contraction cycle that outside air can be drawn into the tank, contaminating the oil.

b. When oxygen and moisture come in contact with oil at high temperatures, the oil's dielectric strength is reduced, and sludge begins to form. Sludge blocks the flow of oil in the tank and severely reduces the transformer's cooling capacity. Various types of tank construction are utilized to accommodate the transformer's expansion and contraction cycles while preventing the oil from being contaminated.

4-5. FREE BREATHING TANKS

Free-breathing tanks are maintained at atmospheric pressure at all times. The passage of outside air is directed through a series of baffles and filters.

Dehydrating compounds (such as calcium chloride or silica gel) are often placed at the inlet to prevent the oil from being contaminated. Free breathing transformers substantially reduce the pressure forces placed on the tank, but are not very effective at isolating the oil. Even if the moisture is removed, the air will still contain oxygen and cause sludging. Also, if the dehydrating cornpounds are not replaced regularly, they can become saturated and begin "rehydrating" the incoming air and adding moisture to the oil.

4-6. CONSERVATOR TANKS

Conservator or expansion type tanks use a separate tank to minimize the contact between the transformer oil and the outside air (see figure 4-l). This conservator tank is usually between 3 and 10 percent of the main tank's size. The main tank is completely filed with oil, and a small conservator tank is mounted above the main tank level. A sump system is used to connect the two tanks, and only the conservator tank is allowed to be in contact with the outside air.

a. By mounting the sump at a higher level in the conservator tank, sludge and water can form at the bottom of the conservator tank and not be passed into the main tank. The level in the main tank never changes, and the conservator tank can be drained periodically to remove the accumulated water and sludge. Conservator tank transformers often use dehydrating breathers at the inlet port of the conservator tank to further minimize the possibility of contamination.

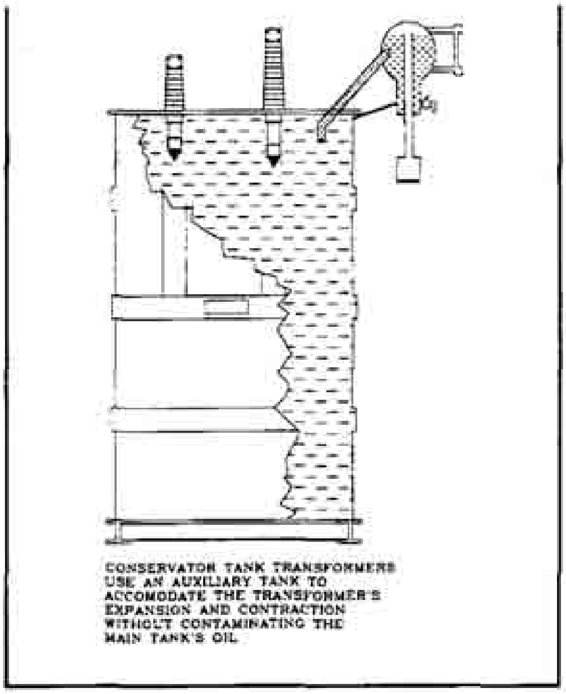

CONSERVATOR TANK TRANSFORMERS USE AN AUXILIARY TANK TO ACCOMODATE THE TRANSFORMER'S EXPANSION AND CONTRACTION WITHOUT CONTAMINATING THE MAIN TANK'S OIL

Figure 4-1. Conservator tank transformers.

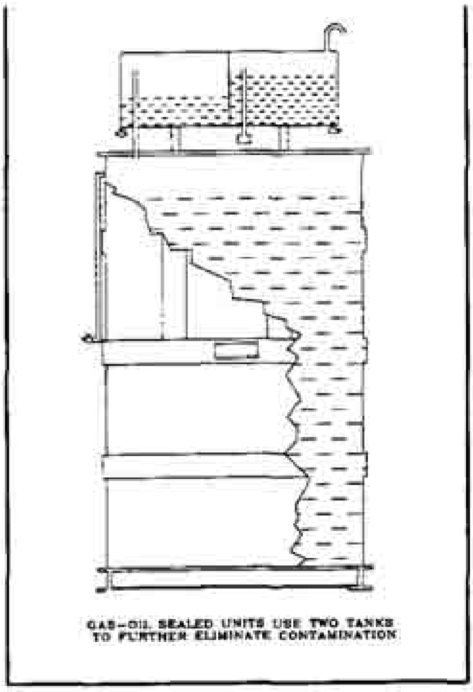

GAS-OIL SEALED UNITS USE TWO TANKS TO FURTHER ELIMINATE CONTAMINATION

Figure 4-2. Gas-oil sealed transformers.

b. Although this design minimizes contact with the oil in the main tank, the auxiliary tank's oil is subjected to a higher degree of contamination because it is making up for the expansion and contraction of the main tank. Dangerous gases can form in the head space of the auxiliary tank, and extreme caution should be exercised when working around this type of transformer.

The auxiliary tank's oil must be changed periodically, along with a periodic draining of the sump.

4-7. GAS-OIL SEALED TANKS

The gas-oil sealed tank is similar to the conservator tank, in that an auxiliary tank is used to minimize the oil's contact with the atmosphere (see figure 4-2).

However, in this type of design, the main tank oil never actually comes in contact with the auxiliary tank's oil.

When the main tank's oil expands and contracts, the gas in the head space moves in and out of the auxiliary tank through a manometer type set-up. The auxiliary tank is further divided into two sections, which are also connected by a manometer. The levels of both sections of the auxiliary tank and main tank can rise and fall repeatedly, and the main tank's oil will never come in contact with the outside atmospheres. The oil in the auxiliary tank is subject to rapid deterioration, and just as in the conservator type, gases and potent acids can form in the auxiliary tank if the oil is not drained and replaced periodically.

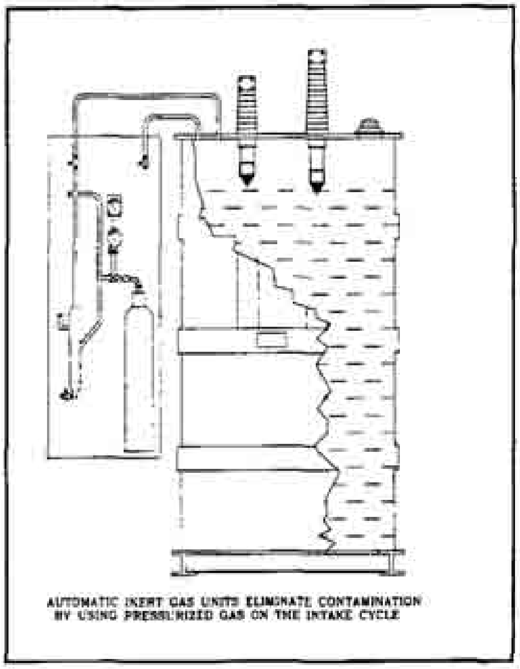

AUTOMATIC INERT GAS UNITS ELIMINATE CONTAMINATION
BY USING PRESSURIZED GAS ON THE INTAKE CYCLE

Figure 4-3. Automatic inert gas sealed transformers.

4-8. AUTOMATIC INERT GAS SEALED TANKS

Some transformers use inert gas systems to completely eliminate contamination (see figure 43). These systems are both expensive and complicated, but are very effective. The pressure in the tank is allowed to fluctuate within certain levels (+/- 5 psi), and any excess pressure is simply bled off into the atmosphere. When the transformer cools and begins its intake cycle, the in-going gas is supplied from a pressurized nitrogen bottle. Nitrogen gas has little detrimental effect on the transformer oil and is not a fire or explosion hazard.

Inert gas systems (sometimes called pressurized gas systems) have higher Initial installation costs, and require more periodic attention throughout their life than non-pressurized gas systems.

4-9. SEALED TANK TYPE

Sealed tank units (see figure 4-4) are the most common type of construction. The tank is completely sealed and constructed to withstand a moderate amount of contraction and expansion (usually +/- 5 psi). This pressure difference will usually cover the fluctuations the transformer will undergo during normal operation.

a. A gas blanket, usually nitrogen, is placed over the oil in the main tank and this "cushion" helps to absorb most of the forces created by the pressure fluctuations.

A slight pressure (around 1 psi) is maintained on the tank to prevent any unwanted influx of air or liquid.

The higher pressures caused by severe overloading, arcing, or internal faults are handled by pressure relief devices.

b. There are many auxiliary systems and devices that are used to maintain the integrity of the tank's seal and to compensate for any extreme or unplanned conditions.

There are also a number of gauges and relays which are covered in chapter 9 that are used to monitor the pressure and temperature conditions inside the tank.

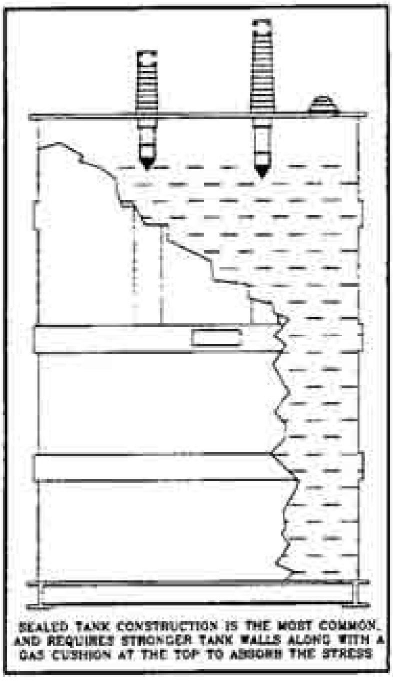

SEALED TANK CONSTRUCTION IS THE MOST COMMON,
AND REQUIRES STRONGER TANK WALLS ALONG WITH A
GAS CUSHION AT THE TOP TO ABSORB THE STRESS

Figure 4-4. Sealed transformers.

CHAPTER 5
INSULATING FLUIDS

5-1. OIL

Although new systems and fluids are constantly being developed, mineral oil is the most common fluid in use today. Polychlorinated biphenyl (PCBs) are not acceptable to the Environmental Protection Agency (EPA) for use in transformers. Any reference to "oil" or "insulating fluid" in this section will be understood to mean transformer mineral oil. The manufacturer's instructions and guidelines should be considered when dealing with fluids.

a. Insulating fluid plays a dual function in the transformer. The fluid helps to draw the heat away from the core, keeping temperatures low and extending the life of the insulation. It also acts as a dielectric material, and intensifies the insulation strength between the windings. To keep the transformer operating properly, both of these qualities must be maintained.

b. The oil's ability to transfer the heat, or its "thermal efficiency," largely depends on its ability to flow in and around the windings. When exposed to oxygen or water, transformer oils will form sludge and acidic compounds. The sludge will raise the oil's viscosity, and form deposits on the windings. Sludge deposits restrict the flow of oil around the winding and cause the transformer to overheat. Overheating increases the rate of sludge formation (the rate doubles for every 10 degree Celsius rise) and the whole process becomes a "vicious cycle". Although the formation of sludge can usually be detected by a visual inspection, standardized American Society for Testing and Materials (ASTM) tests such as color, neutralization number, interfacial tension, and power factor can provide indications of sludge components before visible sludging actually occurs.

c. The oil's dielectric strength will be lowered any time there are contaminants. If leaks are present, water will enter the transformer and condense around the relatively cooler tank walls and on top of the oil as the transformer goes through the temperature and pressure changes caused by the varying load. Once the water condenses and enters the oil, most of it will sink to the bottom of the tank, while a small portion of it will remain suspended in the oil, where it is subjected to hydrolysis. Acids and other compounds are formed as a by-product of sludge formation and by the hydrolysis of water due to the temperature changes. Water, even in concentrations as low as 25 ppm (parts per million), can severely reduce the dielectric strength of the oil. Two important tests for determining the insulating strength of the oil are dielectric breakdown and moisture content.

d. The two most detrimental factors for insulating fluids are heat and contamination. The best way to prevent insulating fluid deterioration is to control overloading (and the resulting temperature increase), and to prevent tank leaks. Careful inspection and documentation of the temperature and pressures level of the tank can detect these problems before they cause damage to the fluid. However, a regular sampling and testing routine is an effective tool for detecting the onset of problems before any damage is incurred.

5-2. OIL TESTING

ASTM has developed the standards for oil testing. The following tests we recommended for a complete analysis of a transformer's oil:

a. Dielectric breakdown (ASTM D-877 & D-1816).

The dielectric breakdown is an indication of the oil's ability to withstand electrical stress. The most commonly performed test is ASTM D-877, and because of this, it is more readily used as a benchmark value when comparing different results. The oil sample is placed in a test cup and an AC voltage is impressed on it. The electrodes are two discs, exactly 1 in. in diameter and placed 0.10 in. apart. The voltage is raised at a constant rate, until an arc jumps through the oil between the two electrodes. The voltage at which the arc occurs is considered the dielectric strength of the oil. For systems over 230 kV, this test is performed using spherical electrodes spaced 0.04 or 0.08 in. apart (ASTM D-1816). Portable equipment is available for performing both levels of this test in the field.

b. Neutralization number (ASTM D-974). Acids are formed as by-products of oxidation or sludging, and are usually present any time an oil is contaminated. The concentration of acid in an oil can be determined by the amount of potassium hydroxide (KOH) needed to neutralize the acid in 1 g of oil. Although it is not a measure of the oil's electrical strength, it is an excellent indicator of the pressure of contaminants. It is especially useful when its value is monitored over a number of sampling periods and trending data is developed.

c. Interfacial tension (ASTM D-971 & D-2285). The interfacial tension of an oil is the force in dynes per centimeter required to rupture the oil film existing at an oil-water interface. When certain contaminants, such as soaps, paints, varnishes, and oxidation products are present in the oil, the film strength of the oil is weakened, thus requiring less force to rupture. For in-service oils, a decreasing value indicates the accumulation of contaminants, oxidation products, or both. ASTM D-971 uses a platinum ring to physically break the interface and measure the force required. ASTM D-2285 measures the volume of a drop of water that can be supported by the oil without breaking the interface.

d. Power factor (ASTM D-924). The power factor is an indication of the amount of energy that ls lost as heat to the oil. When pure oil acts as a dielectric, very little energy is lost to the capacitance charging. Contaminants will increase the energv absorbed by the oil and wasted as heat. The power factor is a function of the phasor angle (the angular displacement) between an AC potential applied to the oil and the resulting current. The test is performed by passing a current through a test cell of known gap, and "sing" a calibrated capacitance or resistance bridge to separate and compare the reactive and resistance portions of the current passing through the oil.

e. Color (ASTM D-1500). The color of a new oil is generally accepted as an index of refinement. For in-service oils, a darkening of the oil (higher color number), observed over a number of test intervals, is an indication of contamination or deterioration. The color of an oil is obtained by comparison to numbered standards.

Although there are charts available, the most accurate way to determine the oil's color is by the use of a color wheel and a comparator. An oil sample is placed in the comparator, and the color wheel is rotated until a match is obtained. This test is most effective when results are compiled over a series of test intervals, and trending data is developed.

f. Moisture content (ASTM D-1533). Moisture content is very important in determining the serviceability of an oil; the presence of moisture (as little as 25 parts per million) will usually result in a lower dielectric strength value. Water content is especially important in transformers with fluctuating loads. As the temperature increases and decreases with the changing load, the transformer's oil can hold varying amounts of water in solution. Large amounts of water can be held in solution at higher temperatures, and in this state (dissolved) the water has a dramatic effect on the oil's performance. Water contamination should be avoided.

(1) Water content is expressed in parts per million, and although water will settle to the bottom of the tank and be visible in the sample, the presence of free water is not an indication of high water content, and it is usually harmless in this state. The dissolved water content is the dangerous factor; it is usually measured by physical or chemical means. A Karl Fischer

titrating apparatus is one of the more common methods of measuring the dissolved water content.

(2) There are other tests available, such as Flashpoint, Viscosity, and Specific Gravity. They are of limited value for interpretation of the oil's quality, but can be used for further investigation if unsatisfactory results are obtained for the tests listed above.

(3) Table 5-1 lists the acceptable values for the laboratory test results for various insulating fluids.

5-3. DISSOLVED GAS IN OIL ANALYSIS

The primary mechanisms for the breakdown of insulating fluids are heat and contamination. An unacceptable insulation resistance value will tell you only that the insulation's resistance is not what it should be; it is hard to draw any conclusions as to why the insulation is deteriorating. The standard ASTM tests for insulating fluids will provide information about the actual quality of the oil, but the cause of the oil's deterioration must be determined by further investigation. Detection of certain gases in an oil-filled transformer is frequently the first indication of a malfunction. Dissolved gas in oil analysis is an effective diagnostic tool for determining the problem in the transformer's operation.

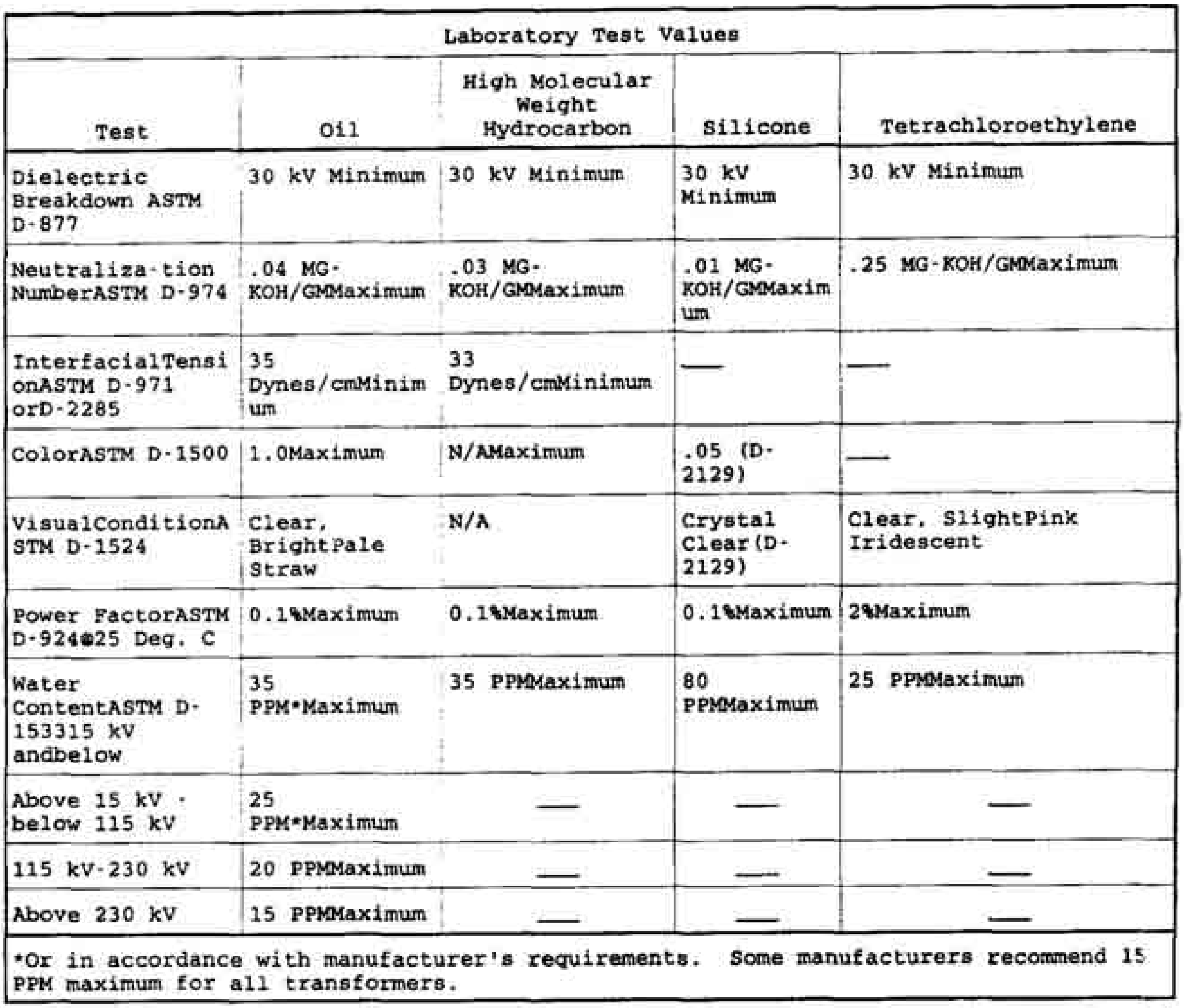
a. When insulating materials deteriorate, when sludge and acid are produced, or when arcing or overheating occurs, various gases are formed. Some of these gases migrate to the air space at the top of the tank, but a significant amount is trapped, or "entrained", in the oil. By boiling off these gases and analyzing their relative concentrations with a gas chromatograph, certain conclusions can be drawn about the condition of the transformer.

b. Gases are formed in the oil when the insulation system is exposed to thermal, electrical, and mechanical stresses. These stresses lead to the following gas-producing events:

(1) Overheating. Even though the insulation will not char or ignite, temperatures as low as 140 degrees Celsius will begin to decompose the cellulose and produce carbon dioxide and carbon monoxide. When hot spot temperatures (which can be as high as 400 degrees C) occur, portions of the cellulose are actually destroyed (by pyrolysis), and much larger amounts of carbon monoxide are formed.

(2) Corona and sparking. With voltages greater than 10 kV, sharp edges or bends in the conductors will cause high stress areas, and allow for localized low energy discharges. Corona typically produces large amounts of free hydrogen, and is often difficult to differentiate from water contamination and the resulting rusting and oxidation. When the energy levels are high enough to create a minor spark, quantities of methane, ethane and ethylene will be produced. Sparks are usually defined as discharges with a duration of under one microsecond.

(3) Arcing. Arcing is a prolonged high-energy discharge, and produces a bright flame. It also produces a characteristic gas (acetylene), which makes it the easiest fault to identify. Acetylene will occur in a transformer's oil only if there is an arc.



Laboratory Test Values

Test	Oil	High Molecular Weight Hydrocarbon	Silicone	Tetrachloroethylene
Dielectric Breakdown ASTM D-877	30 kV Minimum	30 kV Minimum	30 kV Minimum	30 kV Minimum
Neutraliza-tion NumberASTM D-974	.04 MG-KOH/GMMaximum	.03 MG-KOH/GMMaximum	.01 MG-KOH/GMMaximum	.25 MG-KOH/GMMaximum
InterfacialTensionASTM D-971 orD-2285	35 Dynes/cmMinimum	33 Dynes/cmMinimum	—	—
ColorASTM D-1500	1.0Maximum	N/AMaximum	.05 (D-2129)	—
VisualConditionASTM D-1524	Clear, BrightPale Straw	N/A	Crystal Clear(D-2129)	Clear, SlightPink Iridescent
Power FactorASTM D-924@25 Deg. C	0.1%Maximum	0.1%Maximum	0.1%Maximum	2%Maximum
Water ContentASTM D-153315 kV andbelow	35 PPM*Maximum	35 PPMMaximum	80 PPMMaximum	25 PPMMaximum
Above 15 kV - below 115 kV	25 PPM*Maximum	—	—	—
115 kV-230 kV	20 PPMMaximum	—	—	—
Above 230 kV	15 PPMMaximum	—	—	—

*Or in accordance with manufacturer's requirements. Some manufacturers recommend 15 PPM maximum for all transformers.

Table 5-1. Insulating fluids suggested test values

(a) Other conditions that will cause gases to form in the transformer's oil include tank leaks, oil contamination, sludging and residual contaminants from the manufacturing and shipping processes. In most cases, the determinations that can be made are "educated guesses", but they do at least provide a direction and starting point for further investigation. Also, many of the gases can be detected long before the transformer's condition deteriorates to the point of a fault or unacceptable test results.

(b) In general, combinations of elements that occur naturally in pain, such as hydrogen (Hz), oxygen (O2), and nitrogen (N2) reflect the physical condition of the transformer. Higher levels of these gases can indicate the presence of water, rust, leaky bushings, or poor seals.

(c) Carbon oxides such as CO and CO2 reflect the demand on the transformer. High levels of each can show whether the transformer is experiencing minor overload conditions or if it is actually overheating.

(d) The concentrations of hydrocarbon gases, such as acetylene, ethylene, methane and ethane indicate the integrity of the transformer's internal functions.

Acetylene will be produced only by a high energy arc, and the relative concentrations of the others can indicate cellulose breakdown, corona discharge or other faults.

(e) Tables E-2 and S3 show the various gases that can be detected, their limits, and the interpretations that can be made from their various concentrations.

(f) Dissolved gas in oil analysis is a relatively new science, and new methods of interpretation are constantly being devised. The Rogers Binary ratio, The Domenberg Ratios, and the Key Gas/Total Combustible Gas methods are just a few. This type of analysis is still not an exact science (it began in the 1960s), and as its use becomes more widespread and the statistical base of results grows, the determinations will become more refined.

5-4. TRANSFORMER OIL SAMPLING

Samples can be drawn from energized transformers, although extreme caution should be observed when working wound an energized unit. It is good practice, for both energized and de-energized units, to attach an auxiliary ground jumper directly from the sample tap to the associated ground grid connection.

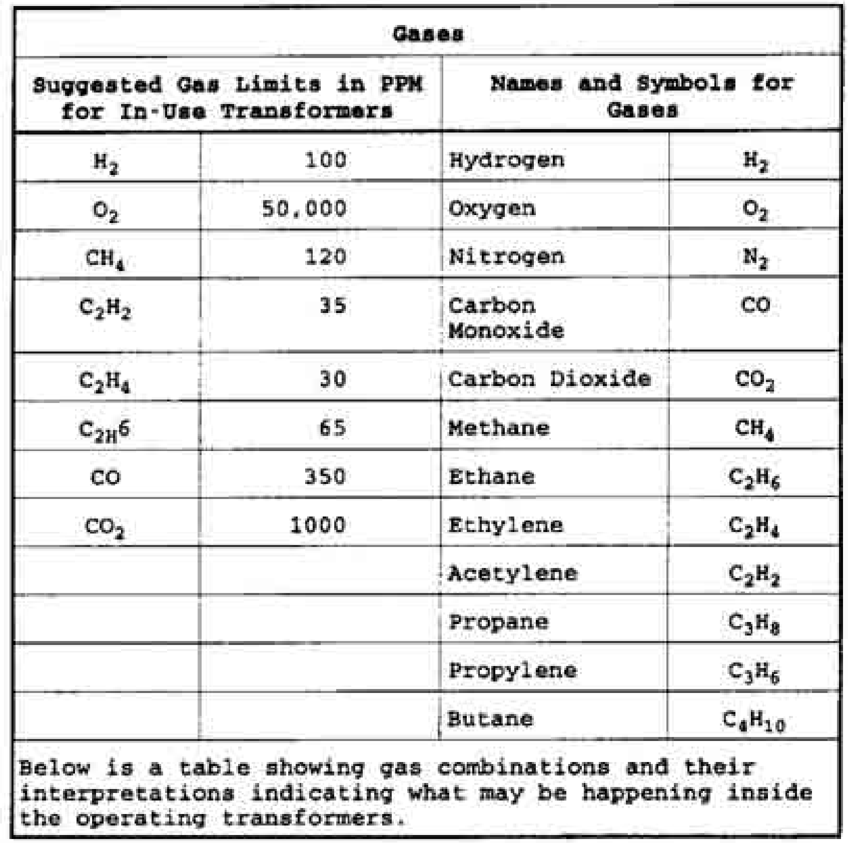
a. During the first year of a testing program, inspections and sampling should be conducted at increased frequencies. Baseline data must be established, and more frequent testing will make it easier to determine the rate of change of the various items. A conservative sampling interval would be taken immediately after energization, and every 6 months for the first year of a newly initiated program. Specialized applications such as tap changers and regulators should be sampled more frequently Except for color and dielectric strength, which can be tested easily in the field, it is recommended that oil analysis be performed by a qualified laboratory

b. Glass bottles are excellent sampling containers because glass is inert and can be readily inspected for cleanliness before sampling. Impurities that are drawn will be visible through the glass. The bottles can be stoppered or have screw caps, but in no instance should rubber stoppers or liners be used; cork or aluminum inserts are recommended. Clean, new rectangular-shaped, I-quart cans with screw caps and foil inserts are also good, especially when gas-in-oil analysis is to be performed. Glass bottles and cans are well suited if the sample must be shipped or stored. For standard oil testing, a small head space should be left at the top of the container to allow for this expansion and contraction. For dissolved gas in oil, the can should be filled all the way to the top to elite the infusion of atmospheric gases into the sample.

c. Because the usefulness of oil testing depends on the development of trending data, it is important for oil samples to be drawn under similar conditions. The temperature, humidity, and loading of the transformer should be documented for each sample, and any variations should be considered when attempting to develop trending data. Samples should never be drawn in rain or when the relative humidity exceeds 70 percent.

Different sampling techniques can alter the results, and steps should be taken to ensure that all samples are drawn properly.

d. When possible, oil samples should always be drawn from the sampling valve at the bottom of the tank. Because water is heavier than oil, it will sink to the bottom and collect around the sampling valve. To get a representative sample, at least a quart should be drawn off before the actual sample is taken. If a number of samples are taken, they should be numbered by the order in which they were drawn.



Gases			
Suggested Gas Limits in PPM for In-Use Transformers		Names and Symbols for Gases	
H_2	100	Hydrogen	H_2
O_2	50,000	Oxygen	O_2
CH_4	120	Nitrogen	N_2
C_2H_2	35	Carbon Monoxide	CO
C_2H_4	30	Carbon Dioxide	CO_2
$C_{2H}6$	65	Methane	CH_4
CO	350	Ethane	C_2H_6
CO_2	1000	Ethylene	C_2H_4
		Acetylene	C_2H_2
		Propane	C_3H_8
		Propylene	C_3H_6
		Butane	C_4H_{10}

Below is a table showing gas combinations and their interpretations indicating what may be happening inside the operating transformers.

Table 5-2. Dissolved gas in oil analysis.

Troubleshooting Chart	
Detected Gases	Interpretations
a) Nitrogen plus 5% or less oxygen	Normal operation, good seals
b) Nitrogen plus 5% or more oxygen	Check seals for tightness
c) Nitrogen, carbon dioxide, or carbon monoxide, or all	Transformer overloaded or operating hot causing some cellulose breakdown. Check operating conditions
d) Nitrogen and hydrogen	Corona, discharge, electrolysis of water, or rusting
e) Nitrogen, hydrogen, carbon dioxide and carbon monoxide corona discharge involving cellulose or severe overloading	
f) Nitrogen, hydrogen, methane with small amounts of ethane and ethylene	Sparking or other minor fault causing some breakdown of oil
g) Nitrogen, hydrogen, methane with carbon dioxide, carbon monoxide and small amounts of other hydrocarbons; acetylene is usually not present	Sparking or other minor fault causing breakdown of oil
h) Nitrogen with high hydrogen and other hydrocarbons including acetylene	High energy arc causing rapid deterioration of oil
I) Nitrogen with high hydrogen, methane, high ethylene and some acetylene	High temperature arcing of oil but in a confined area; poor connections or turn-to-turn shorts are examples
j) same as (I) except carbon dioxide and carbon monoxide present.	same as (I) except arcing in combination with cellulose

Table 5-3. Troubleshooting transformers with detected gases.

e. The sample jars should be clean and dry, and both the jars and the oil should be warmer than the surrounding air. If the transformer is to be deenergized for service, the samples should be taken as soon after deenergization as possible, to obtain the warmest oil during the sampling. The sample jars should also be thoroughly cleaned and dried in an oven; they should be kept warm and unopened until immediately before the sample is to be drawn.

5-5. SYNTHETICS AND OTHER INSULATING FLUIDS

Although there are a number of synthetic compounds available, such as silicone, trichloroethane, and various aromatic and parafinic hydrocarbons, the most common transformer insulating fluids currently in use are mineral oil and PCBs. The use of PCB has been severely restricted, and special attention should be given to its maintenance and disposal.

a. PCB (polychlorinated biphenyl). PCBs have been used extensively in industry for nearly 60 years. PCBs were found to be especially suited for transformer applications because they provided excellent insulating properties and almost no fire hazards. In the 1960s, it was discovered that PCB, and especially the products of its oxidation were harmful to the environment and to the health of personnel. The USEPA began regulating PCBs in the 1980s, and although the regulations are constantly being changed and updated, prudent and conservative policies should always be applied when dealing with PCBs. PCB should not be allowed to come in contact with the skin, and breathing the vapors or the gases produced by an arc should be avoided. Safety goggles and other protective equipment should be worn when handling PCBs. Even though PCBs are no longer being produced, there are still thousands of PCB transformers in the United States alone. Transformers that contain PCBs should be marked with yellow, USEPA-approved stickers. The concentration of PCB should be noted on the sticker, and all personnel working on or around the transformer should be aware of the dangers involved. A PCB transformer should be diked to contain any spills, and all leaks should be rectified and reported as soon as possible. If the transformer requires additional fluid, only approved insulating fluids, such as RTemp should be mixed with the PCB. If the handling and disposal of PCB materials is required, only qualified personnel should be involved, and strict documentation of all actions should be maintained. It is recommended that only qualified professionals, trained in spill prevention and containment techniques, be permitted to work on PCB transformers.

b. Silicone. Silicone fluid is also used widely for many applications. It is nearly as tire resistant as PCB, and provides many of the same performance benefits.

It is also more tolerant of heat degradation and contamination than most other fluids, and will not sludge when exposed to oxidation agents.

(1) The specific gravity of silicone, however, changes with temperature. Silicone's density varies between 0.9 and 1.1 times that of water, which causes water to migrate from the top to the bottom of the tank as the temperature changes. This is especially detrimental in transformers that undergo large or fre-

quent loading and temperature changes.

(2) Silicone also changes in volume more during the temperature changes and this places greater stress on the various gaskets and cowls on the tank. Added pressure compensating and relief devices are usually found on silicone units.

(3) Many other types of insulating fluids are currently in use for specialized applications. Although they may have complex chemical make-ups, most of the maintenance strategies listed in this section will apply. Contamination and overheating are their worst enemies.

The manufacturer's instruction booklets should be referred to when working with these fluids.

CHAPTER 6
INITIAL ACCEPTANCE INSPECTION/TESTING

6-L. ACCEPTANCE

While testing and inspection programs should start with the installation of the transformer and continue throughout its life, the initial acceptance inspection, testing and start-up procedures are probably the most critical. The initial inspections, both internal and external, should reveal any missing parts or items that were damaged in transit; they should also verify that the transformer is constructed exactly as specified. The acceptance tests should reveal any manufacturing defects, indicate any internal deficiencies, and establish baseline data for future testing.

a. The start-up procedures should ensure that the transformer is properly connected, and that no latent deficiencies exist before the transformer is energized. Ensuring that the transformer starts off on "the right foot" is the best way to guarantee dependable operation throughout its service life.

b. Various manufacturers recommend a wide range of acceptance and start-up procedures. Although basic guidelines and instructions are presented here, in no case should manufacturer's instructions and recommendations be ignored. The intent of this manual is to present the practical reasoning behind the procedures recommended by the manufacturer. In some cases, the following procedures will exceed the manufacturer's recommendations, and in others, the manufacturer will call for more involved and comprehensive procedures.

When in doubt, consult the manufacturer's guidelines.

6-2. PRE-ARRIVAL PREPARATIONS

Before the transformer arrives, the manufacturer should be contacted to ensure that all arrangements can be completed smoothly. If possible, the start-up literature or owner's manuals should be provided by the manufacturer before the transformer arrives, so that preparations can be made.

a. Dimensions and lifting weights should be available to ensure that the transformer can be easily moved and positioned. If at the possible, the transformer should be moved to its final installation point immediately on arrival. If the transformer must be stored before energization, steps should be taken to see that the area where it is stored is fairly clean and not exposed to any severe conditions. Regular inspections and complete documentation should be maintained for the transformer while it is stored. Manufacturers will prescribe completely different start-up procedures, depending on how long and in what type of environment a transformer has been stored.

b. The equipment necessary for start-up should be assembled after the site preparations have been completed, and all receiving and unloading arrangements have been made. The following equipment may be necessary, depending on the type of transformer, how it is shipped, and its condition on arrival.

(1) Lifting/moving equipment. If the transformer must be moved, it should be lifted or jacked only at the prescribed points. Most transformer tanks are equipped with lifting eyes, but if they are shipped with their bushings or radiators in place, they will require special slings and spreaders to prevent the equipment from being damaged. Also, it is important to remember to never use the radiators, bushings, or any other auxiliary equipment to lift or move the transformer or to support a person's weight. Having the proper equipment on site will expedite the unloading and placement of the transformer.

(2) Test equipment. Depending on the start-up procedure, any of the following items may be required: A megohmmeter ("megger") insulation resistance test set, transformer turns ratio test set, power factor test set, liquid dielectric test set, dew point analyzer, oxygen content analyzer, and various thermometers and pressure gauges. Sample jars should also be available, and samples should be taken both before and after oil-filling operations.

(3) Vacuum and filtering equipment. Even if the oil being used has good dielectic strength, a good filter will remove any entrained water or contaminants introduced during the filling process. Most transformer oils require a 5micron filter media. The capacity of the vacuum pump will depend on the physical size and voltage rating of the transformer. Larger tanks may require a pump capable of 200 cfm, and transformers with voltages above 69 kV may require a sustained pressure/vacuum level of 2-50 Torr (one torr is a unit of very low pressure, equal to l/760 of an atmosphere). The blank off pressure (the minimum pressure the pump can attain at the inlet) and CFM ratings are usually provided on the pump's nameplate. An assortment of pipe and fittings should also be available to make the necessary connections. An assortment of caps, plugs, and valves should also be available for blanking off any equipment that could be damaged by the vacuum.

(4) Gas cylinders. Nitrogen will be needed for applying the gas blanket and breaking the vacuum. Dry air will be needed if the tank must be entered for inspection or equipment installation. As a safety precaution, bottled pure oxygen must be available anytime anyone enters the tank.

(5) Safety equipment. At least two 20-pound CO2 extinguishers must be available for internal or external use. One 20-pound dry powder extinguisher should be available for use on the exterior of the transformer. All personnel should be thoroughly trained and capable of implementing firefighting, spill containment, first aid, and other emergency procedures.

(6) Miscellaneous equipment. A camera should be available to document any discrepancies that are found during the receiving or internal inspections. Large tents or enclosures will be required if the transformer must be opened or filled in inclement weather. Ladders or scaffolding will be necessary depending on the size of the transformer. Explosion-proof lamps enclosed in a fine stainless steel mesh will be required to provide light inside the tank. Drop cloths or plastic sheets should be used to prevent material from dropping into the tank or winding assembly. AU tools or materials that enter the tank must be accounted for; it is a good idea to attach strings to any small objects that enter the tank.

6-3. RECEIVING AND INSPECTION

When the transformer arrives, all paperwork should be checked to ensure that the transformer is constructed and equipped exactly as specified. Parts lists should be checked and all parts should be counted to ensure that nothing has been omitted. Any auxiliary equipment or shipping crates should be inspected for evidence of damage. Careful attention should also be paid to moisture barriers or waterproof wrappings; if they are torn or damaged, the equipment inside may need to be dried out.

a. The external inspection should be completed before the transformer is unloaded, and, if major problems are discovered, an internal inspection should be conducted. External inspection should verify the following:

(1) Tie rods and chains are undamaged and tight.

(2) Blocking and bracing are tight.

(3) There is no evidence of load shifting in transit.

(4) If there is an impact recorder, whether it indicates any severe shocks.

(5) Whether there are indications of external dam age, such as broken glass or loose material.

(6) Whether there are any obvious dents or scratches in the tank wall or auxiliary compartments.

(7) Whether there is evidence of oil leakage.

(8) Whether there is positive pressure or vacuum in the tank.

(9) Whether porcelain items have been chipped or bent at their mounting flanges.

b. If any of the above items are noted, it should be clearly marked on the delivery receipts, and the manufacturer should be contacted. If an internal inspection is required, the manufacturer's and/or carrier's representatives may need to be present.

6-4. MOVING AND STORAGE

If at all possible, the internal inspection should be conducted before the transformer is unloaded. If the transformer must be unloaded for an internal inspection, it should be moved directly to the point of installation.

a. When unloading the transformer or placing it in position, be sure to use the designated lifting eyes or jacking points. The transformer should be handled in the normal upright position, and in no case should it be tilted more than 15 degrees. Spreaders should be used to hold the lifting cables apart, particularly if they are short and may bear against external assemblies or bushings. Do not attempt to lift or drag the transformer by placing a loop or sling around it, and do not use radiators, bushings, or other auxiliary equipment for climbing or to lift the transformer. Transformers are extremely dense and heavy, much heavier than circuit breakers or other switchgear items. A conservative safety factor should always be applied when a transformer must be lifted.

b. An internal inspection is called for if there is evidence of damage, or if the transformer is to be stored. When the unit is to be stored for more than 3 months, it should be protected from the weather. All scratches or paint defects should be touched up before storage. If the transformer is filled with oil, it should be tightly sealed so that no moisture or air can enter the case. If the transformer is shipped filled with inert gas, periodic inspection should determine that a positive pressure of about 2 psi is maintained at all times. Water-cooled transformers should have the water-cooling coils filled with alcohol or other similar antifreeze to eliminate any danger of freezing or contamination.

c. Regular inspection and documentation procedures should be conducted during transformer storage. All inspection and service procedures should be thoroughly documented, and any discrepancies or adverse conditions should be noted. Pumps and fans should be operated for 30 minutes, once a month. At the end of the storage period, oil samples should be drawn and analyzed for dielectric strength, power factor, and water content. Insulation resistance and power factor tests should be conducted on the transformer and compared to the original factory data.

d. Larger transformers are often shipped without oil. They are vacuum filled with hot oil at the factory to impregnate the winding insulation with oil. The oil is then removed for shipping. This oil impregnation is vital to the winding's insulation strength, and will be lost if the transformer is stored for too long without oil. Most manufacturers recommend a maximum storage time of 3 months without oil. If this storage time is exceeded, hot oil vacuum degasification must be performed, and the manufacturer's guidelines should be followed.

6-5. INTERNAL INSPECTION

If an internal inspection is called for, or if the transformer must be opened to install bushings and other auxiliary equipment, two factors should be of primary importance: (1) to make every attempt to minimize the time the transformer is opened; (2) to take whatever measures necessary to ensure that no moisture, foreign material, or other contaminants enter the tank.

a. The time element can be minimized by assembling all necessary tools and materials before the tank is opened. Personnel conducting the inspection/assembly should review all procedures and be prepared to complete their work as quickly as possible. They should also be prepared to implement any fire fighting or emergency procedures. If the tank must be entered, all personnel should empty their pockets and ensure that no loose debris is in their pant cuffs or on their shoes.

Approved shoe coverings should be worn by anyone who will be on top or inside the transformer. It is also good idea to use drop cloths under all internal work where practical, and to inventory and tie off all tools being used. One person should be responsible for policing the people and materials into and out of the transformer, and for making certain nothing is left in the transformer.

b. Transformers are capable of stepping harmless voltages up to dangerous levels. This applies to both low-level test potentials, and to static charges built up between equipment, windings, tank walls, and personnel.

This danger is further complicated by the flammability of transformer oil. All windings, bushings, pumps, pipes, filter equipment and external connections should be solidly grounded during the inspection, testing, and assembly procedures. Grounds should also be applied to any component of the transformer immediately after a test potential is applied to the component.

c. Transformer tanks are usually pressurized with dry nitrogen for shipping. The pressure must be broken slowly and dry air must be introduced; an oxygen content of 20 to 25 percent should be confirmed before entering the tank. It is important to remember that tank pressures as low as 1 psi will blow covert and fittings off as they are being removed. Ensure that all tank and compartment pressures have been equalized before opening the tank.

d. After the tank pressure has been equalized and the proper oxygen content has been verified, the temperature of the core and coils should be measured. The tank should not be opened unless the temperature of the internal portion of the transformer is at least 2°F above the dew point of the outside air. The dew point is a measure of the ability of the surrounding air to allow moisture to condense on the transformer's surfaces.

e. Dew point measurements of transformers shipped without oil can be made with a number of different instruments. The Alnor Model 7300 is commonly used for transformer start up. Dew point testers operate on the principle that moisture in a gas will precipitate or "fog" in a definite relationship to the temperature and the degree of moisture in the air. By ascertaining that the outside air is low enough in moisture content, and that the temperature of the transformer's components is high enough, the possibility of introducing unwanted moisture into the transformer can be nearly eliminated.

f. Tents and heated temporary enclosures can be used to provide a controlled environment if the work must be completed in inclement weather. Even if the external conditions are satisfactory, it is a good idea to blow a pressurized stream of bottled dry air through the tank while it is open. Creating a slight positive pressure will prevent outside air from entering the tank.

g. If the transformer is shipped filled with oil, the internal inspection can be conducted by lowering the oil level to just above the windings. This can usually be accomplished by installing the radiators and allowing the oil to flow into them. Be certain radiators have been cleaned and pressure checked before installing, and gaskets and valves are installed correctly. An explosion proof spotlight with an oil resistant cord can be lowered into the tank to conduct the inspection.

h. If the oil must be lowered below the winding, and the windings are exposed for more than 24 hours, all of the oil should be removed and the transformer refilled using hot vacuum degassing techniques. Because the equipment required for hot vacuum degassing is rather involved and costly, it is recommended that the manufacturer or qualified professional be present for the operation.

i. The objective of the internal inspection is to locate any damage that may have occurred during shipment.

Examine the top of the core and coil assembly, all horizontal surfaces, and especially the underside of the cover for signs of moisture. All leads, bolted mechanical and electrical joints, current transformers and insulation structures should be thoroughly inspected. The tap changer should be exercised, and all connections verified. Terminal boards should be checked to see that connections are as specified.

j. Although most testing should be performed only while the coils are submerged in oil, if the inspection is being conducted because of problems noted during the external or internal inspections, the following tests should be conducted:

(1) Power factor tests for all winding to ground and windings to winding values.

(2) Turns ratio tests for all windings and tap positions.

(3) Ratio and polarity tests for all current, transformers.

(4) Winding resistance checks for all primary and secondary windings.

(5) Discount the grounding connections between the core assembly and the tank, and perform insulation resistance tests with a megger.

k. These test values should be compared to the factory supplied test data. All temperature and humidity readings should be recorded to facilitate this comparison.

6-6. TESTING FOR LEAKS

If the test results indicate a moisture or contamination problem with the transformer, if the gauges register zero pressure on arrival, or if moisture is discovered during the internal inspection, the transformer should be tested for leaks before final vacuum filling begins.

a. Most transformers are pressurized to approximately 3 psi for shipping. It is important to remember that this pressure will fluctuate according to temperature; a zero pressure gauge reading is not a sure sign of a leak. If the pressure registers zero in the sunlight and at nighttime (over a range of more than 10 degrees F), then a leak can be suspected.

b. Leaks can be detected by applying a positive pressure to the tank. All bushings, radiators, gauges and auxiliary equipment should be installed before a leak check is conducted. Some items may need to be blanked off for the pressure check, and the pressure should be raised slowly so as not to damage the sudden pressure relay or any other sensing devices. Verify the maximum pressure capabilities of the tank (usually found on the nameplate or in the shipping specifications) and use bottled nitrogen to apply the pressure, being careful to always stay at least 1 psi below the maximum allowable. If the tank is empty, a soap/glycerin solution should be applied to all seams, gaskets and fittings. Bubbling and sputtering noises will indicate the location of the leak. If the tank is filled with oil, the soap solution should be applied above the oil level, and chalk dust applied below the oil level. Chalk dust will darken noticeably where any oil is seeping out.

c. Small leaks at seams and welds can be carefully hammered shut with a ball peen hammer, although larger ones may require welding or epoxy patching.

Leaking gaskets should be replaced, and fittings can usually be removed and resealed using glyptal, teflon tape, or other sealing compounds. The manufacturer should be contacted to ensure the use of proper compounds.

Vacuum filling operations can begin once the leads have been replaced and the interior of the transformer has been determined to be dry.

d. The core and coils may need to be dried if a major leak was found, if the transformer has been opened for an extended period, or if unsatisfactory test results were obtained for any of the preliminary testing.

Drying the transformer is an involved and potentially damaging process; effective drying of the core insulation requires temperatures in excess of 90 degrees C. Manufacturers recommend a variety of procedures for drying and determining when the transformer is sufficiently dry. The manufacturer should be contacted if excessive moisture is suspected.

6-7. VACUUM FILLING

New oil can contain enough contaminants to cause a fault when the transformer is first energized. The presence of small quantities of contaminants will begin on ongoing degradation of the oil's quality. The quality of transformer oil depends on its purity; many factors in shipping and storage cannot be controlled once the oil leaves the refinery. The most effective way to ensure that no impurities are introduced into the oil is to filter the oil and fill the tank under vacuum. Filtering will remove any entrained water or other contaminants, and as the stream of oil hits the vacuum, most small bubbles will be drawn out of the liquid and "explode" as they equalize with the vacuum condition in the tank.

a. Oil should be tested before it is introduced into the transformer. This should include field testing for dielectric, and drawing samples for laboratory analysis.

If problems are encountered later, the results of this testing can provide valuable information for determining why and how problems are occurring. Testing also provides a good indication of how effective the filtering and vacuum operations were.

b. Before vacuum filling operations can begin, it is important to determine the maximum vacuum level the tank can withstand, and to ensure that any auxiliary devices can also withstand the same vacuum level.

Items such as conservator tanks and compartment dividers will not be capable of withstanding the full vacuum applied to the tank. Additional pipe and fittings must be used to valve off or equalize the pressure that will be created by the vacuum. Other items, such as dehydrating breathers and pressure vacuum bleeders will have to be removed or valved off. It is important to consult the manufacturer's literature on these devices before applying the vacuum.

c. It is also important to remember that the tank will deflect according to the varying pressures. All rigid connections to the tank, except at the base, should be disconnected before applying the vacuum. This is especially true for bushings, lightning arresters, and other porcelain equipment.

d. Once the necessary preparations have been made, the vacuum/filtering apparatus should be connected as shown in figure 6-l.

e. When hooking up the equipment and applying the vacuum, the following conditions should be observed:

(1) All pipe connections from the pump to the transformer tank should be as short and as large in diameter as possible.

(2) All transformer leads, pumps, and bushings should be grounded to prevent the build-up of static charge.

(3) The vacuum gauge should be installed on the top of the tank itself, and not on any of the vacuum lines. Use an aneroid or thermocouple gauge; the use of mercury gauges is recommended only if provisions are made to contain the mercury in the event that the gauge is broken.

(4) The oil inlet should be positioned so that oil will not enter the vacuum pump. A liquid trap should be installed in the vacuum lines to protect the pump from the oil.

(5) The flow of oil should be controlled so that oil cannot enter the sudden pressure relay or other auxiliary equipment.

(6) All valves to radiators and heat exchangers should be open.

f. Once the equipment has been assembled, make certain that enough oil is on site to complete the job without stopping. During the vacuum and liquid-filling operations, the temperature of the core and coils must be above zero degrees C. The oil temperature should be at least 2 degrees C higher, but in no case less than 10 degrees C. The length of time and the magnitude of the vacuum will depend on a number of factors, including the size of the tank, the length of time the tank was opened, and the voltage rating of the transformer. The individual manufacturer's recommendations should be consulted, and the following times should be considered as minimums:

(1) Apply the vacuum for at least 3 hours before oil-filling begins.

(2) Never allow the vacuum to fall below 80 percent of the original level while pumping the oil in.

(3) Maintain the vacuum for at least 3 hours after the transformer is full.

g. While the vacuum is being applied, the transformer is especially susceptible to contamination by outside factors. There should be no leaks in the tank, hoses, or any of the auxiliary equipment, and the entire set-up should be protected from rain or moisture.

h. When the tank has been filled to the proper level, the vacuum should be broken slowly with nitrogen and pressurized to 3 psi. Once the pressurized nitrogen is applied, the cooling pumps should be operated for at least 1 hour to reduce the possibility of trapped residual gas. The transformer should then be allowed to stand without load for at least 12 hours before any tests are performed.

i. After the 12-hour standing period, the following tests should be performed to establish baseline data for the transformer.

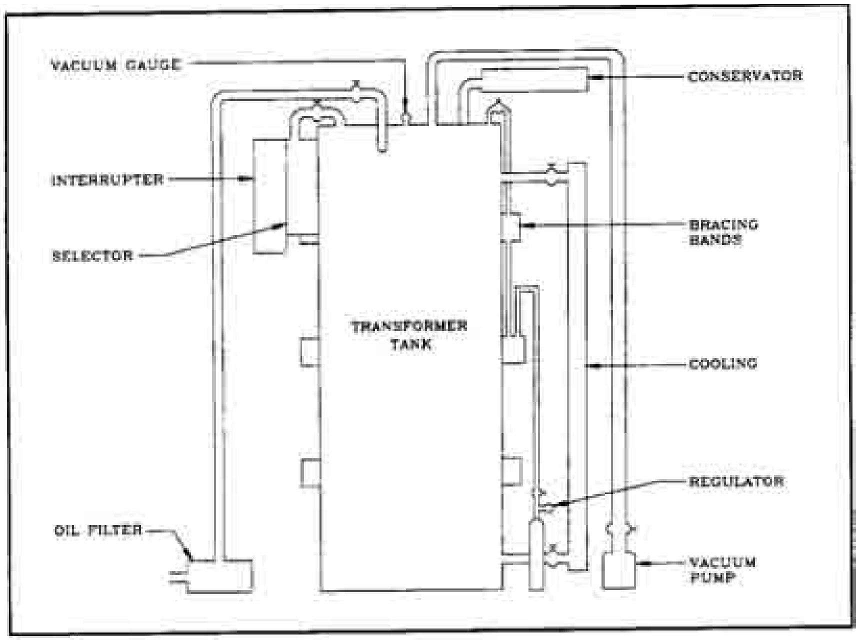


Figure 6-1. Transformer tank with vacuum filling.

(1) Transformer turns ratio. This test ensures that no material or tools are shorting the windings.

(2) Insulation resistance-dielectric absorption.

This test is used to determine whether any grounds have been left on the windings, and whether the insulation quality is strong enough for energization.

(3) Winding continuing resistance test. This test should be compared to the factory-supplied readings; a reading that is ore than 10 percent higher could indicate loose internal connections.

(4) Power factor test. This test will indicate the quality of the combined insulating fluid and winding insulation. It will also provide important baseline data for future testing. Values in excess of 1 percent could indicate dampness in the transformer. Consult the manufacturer's instructions for drying procedures.

(5) Insulating fluid testing. This test will help to provide additional information if any discrepancies are noted in the

above testing. Samples should be drawn for the complete series of lab tests, including dissolved gas, and dielectric strength field testing. The dielectric strength for new oil should be at least 35 kV.

j. After the testing is completed, the transformer should be energized for at least 12 hours before applying the load. Because very high currents can be developed when the transformer is first energized, any upstream fuses or fused devices should be checked immediately after the power is applied. If a fuse should blow, and if the transformer is allowed to operate without one or two fuses, it could be damaged, even if no load is applied.

k. After 12 hours, the load should be applied slowly, and the transformer should be carefully monitored as the load is being applied. Even though satisfactory test results have been obtained, personnel should stay clear of the transformer during the first 24 hours of energization. It is during this time that any entrapped air will come to the surface, and the possibility of a fault or a short should always be considered.

l. All of the acceptance test data should be recorded and used as baseline data for future testing. It is a good idea to keep copies of all test data, start-up documentation, and product information in a file cabinet with all of the other electrical system documents. The proper documentation, storage and accessibility of all product information, tests and procedures is one of the most important factors in a comprehensive and effective maintenance program.

CHAPTER 7
TRANSFORMER TESTING

7-L. TEST DATA

Electrical performance testing is one of the most important components of a comprehensive maintenance program. Test data, when taken under, or corrected to, standard conditions, will yield valuable data about the rate of deterioration of a piece of electrical equipment. Once this rate is determined, service factors can be adjusted, and potential problems alleviated.

a. Almost all electrical failures, in all sorts of electrical equipment, can be traced to a failure of the insulation.

Periodic testing will indicate the condition of the insulation at the time of the test, but does little to show the actual amount of deterioration the insulation has undergone during its service life. Only by establishing baseline data and performing regular tests under controlled conditions can trending data be developed to yield true indications of the insulation's condition.

b. Insulating fluids analysis is probably the most practical and indicative test of a transformer's condition.

It provides the opportunity to actually remove a portion of the transformer's insulation and subject it to a series of standardized tests under controlled laboratory conditions, with the benefit of complex laboratory equipment. One of the most important links in the effectiveness of insulating fluids testing is the quality of the sample.

c. Except for sampling and inspection, all transformer tests should be performed on de-energized equipment. Even for sampling and inspections, the tank ground should be verified before coming into contact with any of the transformer's outer surfaces. The tests listed in this chapter and in chapter 10 should be performed only after the circuits are de-energized and checked both at the source and at the test location. See the safety procedures in chapter 1.

d. One of the most important factors in conducting transformer tests is the condition of the unit under test. A thorough inspection of the unit should be performed before the test, and any questionable conditions should be noted on an inspection record. All temperature and pressure readings should be recorded along with the atmospheric conditions (temperature and humidity) at the time of the test.

e. Test procedures should be as similar as possible from one test to another. All connections, test voltages and time intervals should be repeated exactly for each test cycle. By performing the tests in a set method, and correcting all test results to a standard temperature value (20 degrees C), the data for different test intervals can be compared to indicate the rate of deterioration of the transformer.

7-2. DIRECT CURRENT TESTING

Transformer tests can be divided into two categories, alternating current (AC) and direct current (DC). Direct current testing is widely accepted because of the portability of the equipment and because of the non-destructive nature of the tests. Because the test potential can be applied without the reactive component (capacitive and inductive charging and recharging), DC tests can be performed at higher levels without stressing the insulation to the same degree as an AC test. It is important to note that, even though a winding failure may result, it probably resulted from an incipient condition that the test was designed to detect. If the deficiency had gone undetected, the failure may have occurred at an unplanned time and resulted in additional equipment damage.

a. When a DC potential is applied across an insulation, there are three components to the resulting current.

An understanding of the nature of these currents will help with the application of the tests and the interpretation of the resulting data.

(1) Capacitance charging current. When the insulation resistance is being measured between two conductors, the conductors act like the plates in a capacitor.

These "plates" absorb a certain amount of electrical energy (the charging current) before the applied voltage is actually developed across them. This current results in stored energy that should be discharged after the test by shorting across the insulation.

(2) Dielectric absorption current. As noted above, the two conductors between which the potential is being applied act like a capacitor. The winding insulation and the insulating fluid then act as dielectric materials and absorb electrical energy as their molecules become polarized, or charged. The absorption current decreases as the materials become charged, resulting in an apparent increase in the insulation resistance.

The absorption current results in stored energy that takes longer to dissipate than it did to build. The insulation should be shorted for a time period equal to or longer than the time the test was applied, preferably longer.

(3) Leakage current. This is the current that actually flows throughout the insulation or across its surface. Its magnitude is usually very small in relation to the rated current of the device, and it is usually expressed in microamperes (one millionth of an amp).

It indicates the insulation's actual conductivity, and should be constant for a steady applied voltage.

Leakage current that increases with time for a constant applied voltage indicates a potential problem.

b. The following tests are designed to provide indications of the transformer's condition and suitability for service. The recommended frequency and relationship in a comprehensive maintenance/testing program is discussed in chapter 10.

(1) Insulation resistance-dielectric absorption testing.

The insulation resistance test is probably the best known and most often used electrical test for insulation.

It is used primarily to detect low resistance paths to ground or between windings that result from carbonization, deterioration, or the presence of moisture or dirt. It will not indicate the actual quality of the insulation, but when conducted under controlled conditions, with the data compiled for a number of service intervals, trending data can be developed, and definite conclusions can be drawn as to the insulation's rate of deterioration.

(a) High- and medium-voltage insulation systems are usually designed to withstand large potentials and large quantities of electricity. Because of this, special equipment must be used to perform resistance tests. Ohm's Law applies for all systems, and no matter how high the applied voltage, or how "resistance" the insulating material, there will be a measurable leakage current, and there will be a resultant resistance value.

Because of these conditions, leakage currents are usually stated in micro-amps (one millionth of an amp) and resistance values in megohms (one million Ohms).

Most hand-held meters are not capable of reading these extremes accurately, and special equipment is used. Even if a unit can read these extremes accurately, it must also be able to supply the necessary quantities of electricity to charge the massive conductors and contacts found in a transformer.

(b) An insulation resistance test is usually performed with a megger, an instrument that is not only capable of reading high resistance values, but is also able to produce the necessary currents and voltages to obtain the readings. Megger test potentials are usually applied at 500, 1,000, 2,500, and 5,000 volts DC. These potentials are obtained by using a motor driven or hand-crank operated magneto. The hand crank units are both lightweight and portable, and because they require no batteries or external source, they are also extremely dependable. Motor-driven units, on the other hand, are capable of achieving higher and more constant test voltages, but are practically useless without batteries or an external source. Both units are available in models capable of producing accurate readings for resistance levels as high as 100,000 megohms.

(c) The following conditions should be observed when performing an insulation resistance test: Make sure that both the tank and core iron are solidly grounded. Disconnect any systems that may be connected to the transformer winding, including high- and low-voltage and neutral connections, lightning arrestors, fan systems, meters, and potential transformers.

Potential transformers are often located on the line sides of breakers or disconnects; when the disconnect is opened, there will still be a path available to ground. Short circuit all high- and low-voltage windings together at the bushings connections; jumpers should be installed to ground, and no winding should be left floating. The ground connection on grounded windings must be removed. If the ground cannot be conveniently removed, the test cannot be performed on that winding. Such a winding must be treated as part of the grounded circuit.

(d) Using a megohmmeter with a minimum scale of 20,000 megohms, measure the insulation resistance across the connections as shown in figure 7-l.

(e) The terminal markings are referenced as follows: The L terminal is the line or "Hot" terminal of the instrument, where the test potential is generated. The E terminal is the "Earth" or ground connection. The G terminal is the "Guard" terminal, it is used to isolate a certain portion of the circuit from the test.

(f) These test connections are considered the bare minimum for a maintenance testing cycle, and should be applied only to a transformer that has already been in service. They will not detect shorts between the individual windings on the high or low side. For acceptance testing, or for investigative purposes, the tests diagramed in figure 7-7 can be applied.

(g) The test voltages should be as close as possible to the voltage rating of the component to which it is being applied. Suggested test voltages are found in table 7-1.

(h) All final insulation resistance values should be corrected to 20 degrees C to compensate for varying conditions at the time of the test, and to allow for comparison of readings taken at different test intervals. The winding temperature, and not the atmospheric temperature, should be used for insulation resistance tests. It is important to note that when a transformer is de-energized, there is a proportional change between the actual temperature of the windings and the exterior tank or oil temperature indicated by the temperature gauges.

Average readings should be taken for various points on the transformer tank, and then the insulation resistance readings corrected to 20 degrees C. This is accomplished by applying the conversion factors in table 7-2.

(i) There are many schools of thought as to what is considered an acceptable insulation resistance value.

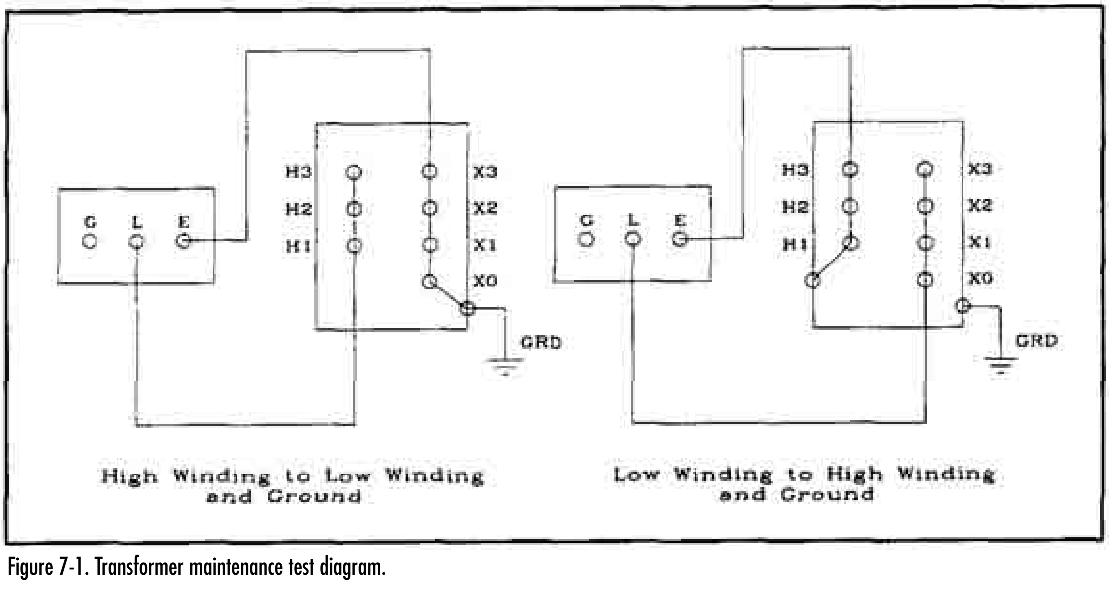

G
L
E
H3
H2
H1
X3
X2
X1
X0
GRD
High Winding to Low Winding and Ground
G
L
E
H3
H2
H1
X3
X2
X1
X0
GRD
Low Winding to High Winding and Ground

Figure 7-1. Transformer maintenance test diagram.

A widely accepted rule of thumb for insulation resistance values is “the kV rating of the item under test plus one megohm.” This should be considered as a bare minimum value, and any values equal to five times this amount should be investigated. If the investigation reveals nothing, then the humidity and condition of the item under test should be considered. A 10 megohm resistance value for a piece of 5 kV equipment should not be accepted without investigation, but if the humidity is high, and the insulation is dirty, that value may be acceptable.

(j) The final criterion for evaluating insulation resistance values should be the amount of change from the manufacturer’s factory test values, or from the last test interval. The manufacturer should be contacted if any values are significantly lower than the factory values.

(k) To obtain useful data that is indicative of the dielectric capabilities of the transformer’s insulation, it is recommended that a polarization index or dielectric absorption ratio be computed for all resistance readings.

The polarization index is determined by holding the applied voltage of the megohmmeter constant, and taking resistance readings at the end of l- and 10-minute intervals. The apparent increase in the resistance is due to the dielectric charging of the insulation.

The polarization index is computed by dividing the l-minute value into 10-minute value.

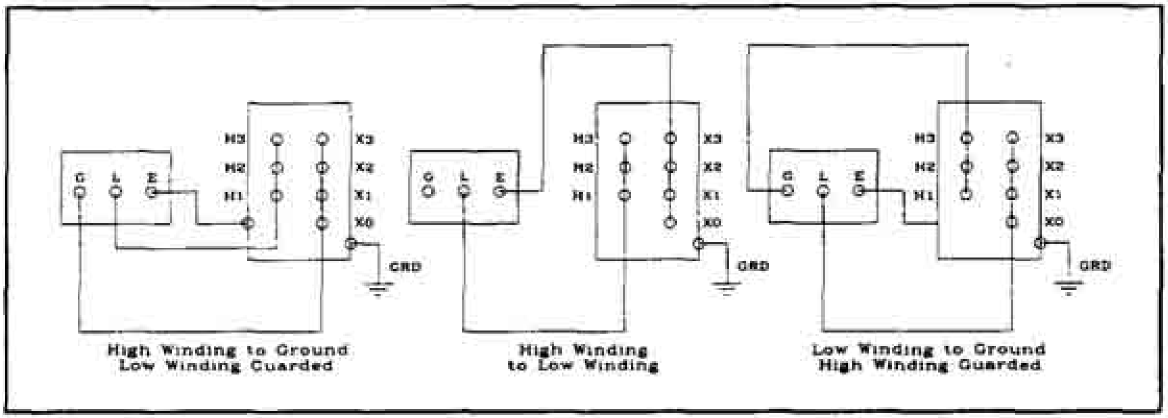


Figure 7-2. Transformer acceptance test diagram.

(1) The dielectric absorption ratio is computed in the same way, except that 60-second intervals are used. These values should, theoretically, be independent of temperature or other outside factors.

(m) The polarization index and dielectric absorption ratios are also subject to different methods of interpretation. In any case, they should always be greater than one, and any downward trend in their value over a number of test intervals indicates deterioration that should be investigated.

(2) Winding resistance measurements. If a measurement of the winding resistance shows no appreciable change from the factory test values, then it can be assumed that there are no loose connections.

Maintenance testing should include only the applied tap position. Three-phase wye windings should be measured phase to neutral, and delta windings should be separated to read individual windings, if possible. If the windings cannot be separated, three separate readings should be taken, with each winding measured in parallel with the other two, and the results evaluated as a function of the parallel and series connections involved. In this instance, the comparison of the three readings (the difference should be no greater than 1 percent) will indicate whether or not there are any problems.

(a) The winding resistance can be measured with a low resistance ohmmeter, or with a Kelvin bridge. Be sure to make good contact with the winding leads, and to wait 3 minutes after initial contact before taking a reading. This delay is necessary due to the induction created by the transformer windings.

Because the windings will store energy, it is important to shut off the test set and allow the energy to dissipate before removing the test leads.

(b) If the factory test values are available, or if the transformer cannot be disconnected, the resistance values for each winding should be compared to those of the adjacent windings. A difference of one percent indicates a potential problem.

(3) Contact resistance. Loose connections can result in overheating and possible equipment, failure.

All high- and low-voltage and ground connections should be inspected, and if any abnormal conditions are noted, the contact resistance should be measured to ensure that solid contact is being made. This testing works especially well in conjunction with infrared scanning. If a connection shows hot on the IR scan, and its contact resistance cannot be lowered by tightening, it should be replaced.

(4) DC high potential testing. The DC high potential test is applied at above the rated voltage, and can cause damage to the transformer if special precautions are not taken. When a leakage current passes through the insulation system of an oil-filled transformer, different amounts of the total voltage are dropped in the solid (paper) and liquid (oil) parts of the insulation.

These voltage drops are caused by the resistance of each insulating component, and heat is created. Under normal AC operation, only a small amount (l/4) is dropped across the solid insulation. The remaining 3/4 is dropped in the oil, where the heat can be easily dissipated, and little harm is done.

(a) When a DC potential is applied, nearly 3/4 of the voltage is dropped across the solid insulation. This changing stress is further complicated when higher than operating level voltages are applied. DC overpotential testing is of little value as a maintenance test, and is usually conducted for acceptance purposes, or after repair of transformers. In any event, high potential testing should not be conducted unless a satisfactory result is obtained for the insulation resistance. It is highly recommended that the manufacturer be contacted before performing this test, and that only manufacturer’s procedures be followed in conducting this test.

(b) DC Step Voltage Testing is often performed on transformers at less than the rated voltage of the winding under test. Voltages are applied in equal increments at timed intervals (usually 1 minute) and the rate of change of the leakage currents is monitored. When the applied potential is plotted against the leakage currents (on Log-Log paper) the rate of change should yield a reasonably linear slope. Leakage current jumps of more than 100-150 percent times the previous value usually indicate a problem, and the test should be discontinued so that the circuit can be investigated. Like all of the other tests, this test is especially useful when repeated tests over extended time intervals are considered, and trending data is generated.

7-3. ALTERNATING CURRENT TESTING

AC testing is especially valuable when the transformer's reactive capabilities are to be measured. For maintenance testing, this includes power factor testing (measuring the capacitive quality of the insulation system) and turns ratio testing (measuring the inductance that links the primary and secondary). Although AC testing requires more energy to perform at the rated frequency, and larger test sets are involved to reach the same operating levels as DC, AC testing more closely simulates the operating condition of the transformer.

The following tests are recommended for regularly scheduled maintenance:

a. Transformer turns ratio. The transformer turns ratio (TTR) test is used to determine, to a high degree of accuracy, the ratio between the primary and secondary of the transformer. This test is used to verify nameplate ratio, polarity, and tap changer operation for both acceptance and maintenance testing. It can also be used as an investigative tool to check for shorted turns or open windings. If the turn-to-turn insulation begins to break down in either winding, it will show up in successive TTR tests.

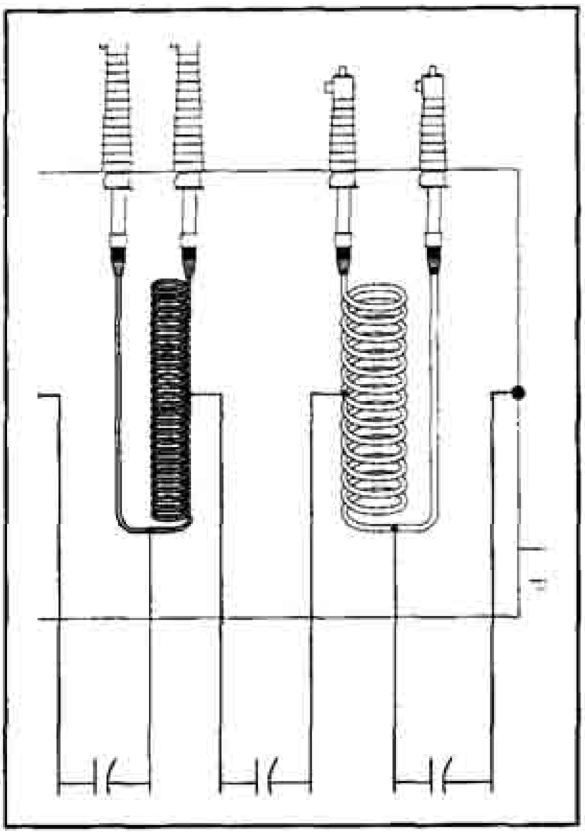


Figure 7-3. Winding losses in a transformer with uncontaminated dielectric.

(1) Although there are a number of methods available, the most accurate method is by the use of a null balance test set. The ratio determined by the test set should agree with the indicated nameplate voltage ratio, within a tolerance of +/- 0.5 percent.

(a) If a high exciting current is developed at low voltage, it could indicate a short in the windings or an unwanted short across the exciting clamps.

(b) If there is a normal exciting current and voltage, but not galvanometer deflection, there is the possibility of an open circuit or a lack of contact at the test leads.

(c) Actual test results for most transformers will show a slight ratio difference for the different legs of the core, due to the different return paths for the induced magnetic flux.

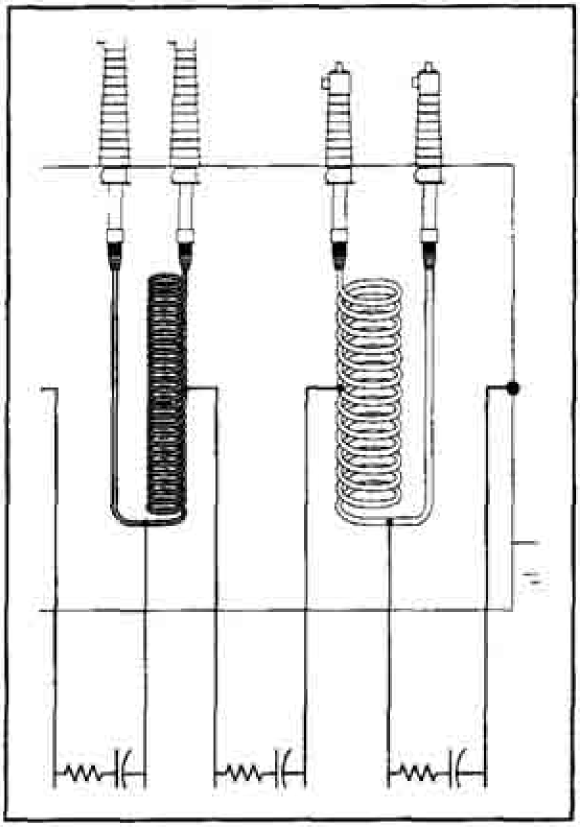


Figure 7-4. Winding losses in a transformer with contaminated dielectric.

(2) The transformer ratio can also be computed by applying a voltage to the primary, and using two volt meters to read the voltage applied to the primary and the voltage induced in the secondary. This method depends on the combined accuracies of both volt meters, and is usually accurate to only about 1 percent.

b. Insulation power factor. Insulation power factor is similar to system power factor, in that it is a ratio of the reactive and resistance components (apparent and real power) of the applied potential. However, where it is desirable to have a system power factor as close as possible to one (purely resistance), an insulation's power factor is expected to be as Neal zero (purely capacitive) as possible. Insulation power factor is more akin to the dissipation factor that is used as a criterion to evaluate the efficiency of capacitors. The transformer's insulation is expected to perform as a capacitor.

(1) Any time two conductors are at different potentials, there is a capacitance between them. There is a capacitance between the individual windings, and between each winding

and the tank in a transformer.

The oil and cellulose insulation that separate the windings from each other and from the tank act as dielectric materials when an alternating current is applied.

Uncontaminated oil and winding insulation are excellent dielectric materials, and will consume little energy in the capacitive charging and discharging that occurs in an AC system. This charging current is expressed in volt amperes, and under ideal conditions, is completely returned to the system in each full cycle. Figure 7-3 illustrates this relationship.

(2) The capacitive nature of the insulation changes as the oil becomes contaminated. Contaminants consume energy in the charge/discharge cycle, and this energy is lost as heat. Because this power is consumed and dissipated as heat, it appears as a resistive component, and can be expressed in watts. The diagram in figure 7-3 is modified in figure 7-4 to show this resistive component.

Power factor testing is performed by measuring the total volt-amperes drawn by the system. A capacitance bridge, resistance bridge, or combination of volt, amp, and watt meters is used to separate the resistance and reactive components. The power factor is then expressed as a ratio of the resistive energy that is consumed as heat (watts), to the apparent (vector sum of reactive and resistance) energy that flows into the system (volt-amperes). Figure 7-5 shows a typical metering system for measuring power factor. The power factor can also be expressed as a function (the cosine) of the phase angle between the applied voltage and the resulting current. If the insulation was purely resistive, the current would occur at exactly the same time as the voltage was applied (the phase angle, or displacement, between the current and the voltage would be zero).

The cosine of 0 degrees is one, representing a 100 percent power factor.

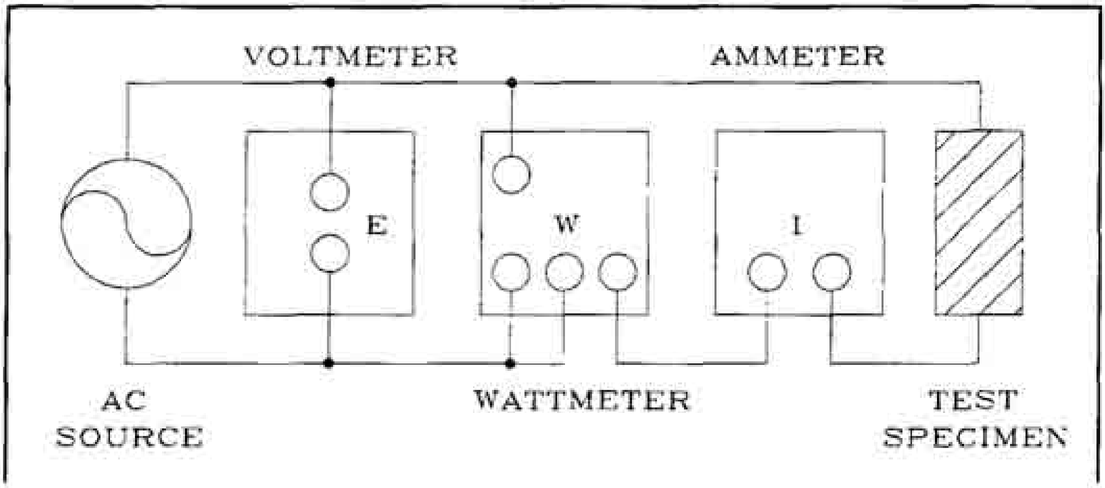


Figure 7-5. Voltmeter-ammeter-wattmeter method of measuring insulation power factor.

(3) If the insulation were purely capacitive (an ideal condition), the voltage would not reach its maximum until 90 degrees after the current had already reached its maximum. The cosine of 90 degrees is zero, representing a zero percent power factor. The ideal situation is a purely capacitive insulating quality; the existence of a minor resistive component produces a slight angular shift or displacement (a marginally acceptable power factor of 1 percent corresponds to a phase angle of 89.43 degrees, or a displacement from ideal configurations of 0.57 degrees).

(4) Any insulating medium will have a measurable power factor. Power factor tests are performed on transformers, bushings, circuit breakers, and even on insulating fluid (a special can is used to provide a controlled environment). Bushing power factor measurements are especially useful, and most larger bushings have a special voltage tap that provides a standard reference point between the conductor and ground.

Bushings without this tap require a “hot collar” test (see figure 7-6), where the potential is applied to the outer surface of the bushing material and leakage currents are measured through the ceramic or epoxy of the bushings material.

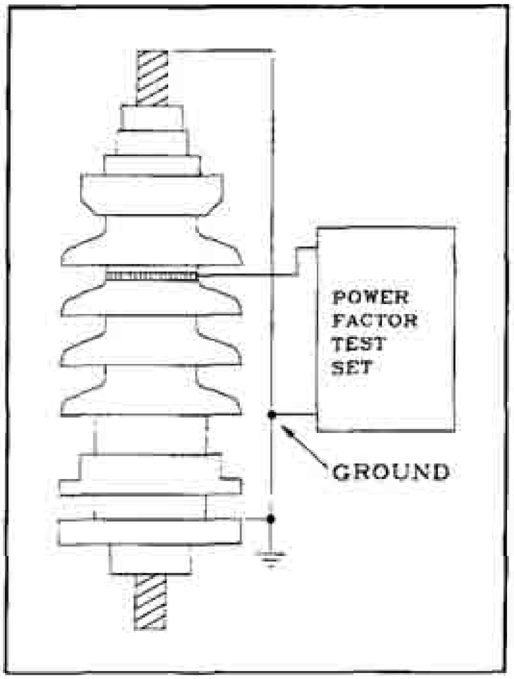


Figure 7-6. “Hot collar” busing power factor text.

(5) Another application of the power factor test is the “tip up” test, where the power factor is measured at two different potentials (usually 2.5 and 10 kv) and the results are compared. Because the power factor is a pure ratio, the results should be independent of the applied potential, and any differences will reflect the presence of moisture or other impurities that are affected differently by different applied potentials.

(6) The power factor can be measured by a metering arrangement, or by using a capacitance or resistance bridge. The quantities being measured are not only small, but they are also quite small in relation to each other. Because of these magnitudes, and because the power factor is usually determined to the tenth of a percent, it is important that the instrument(s) being used have a high degree of accuracy and reproducibility. This is

best accomplished with a unitized test set.

(7) Although AC overpotential tests are performed on new transformers at the factory (BlL, induced voltage, and various loss measurements), they are potentially damaging, and are of little value for maintenance purposes.

Also, because an AC test set must be able to achieve test potentials at alternating frequencies, relatively large sets are required to effectively charge and discharge large transformers. It is recommended that the manufacturer be contacted before performing any AC tests at above the rated voltage. In any case, the transformer should have already passed the other tests listed here, and the possibility of transformer failure should always be considered when conducting these tests.

(8) The true value of tests is realized when conducted in exactly the same manner, over a number of test intervals.

CHAPTER 8
TRANSFORMER AUXILIARY EQUIPMENT

8-L. AUXILIARIES

Even though the transformer is basically a static device, many changes in pressure and temperature are constantly occurring. The temperature and pressure changes must be monitored and their changes compensated.

Also, because of the transformer's high voltage and power capabilities, there are areas of extremely high voltage stress, and many opportunities for large surges and fault conditions. The following auxiliary equipment is used to monitor and compensate for many of these factors, and can be found on most power transformers.

8-2. BUSHINGS

The leads from the primary and secondary windings must be safely brought through the tank to form a terminal connection point for the line and load connections.

The bushing insulator is constructed to minimize the stresses at these points, and to provide a convenient connection point. The bushing is designed to insulate a conductor from a barrier, such as a transformer lid, and to safely conduct current from one side of the barrier to the other. Not only must the bushing insulate the live lead from the tank surfaces, it must also preserve the integrity of the tank's seal and not allow any water, air, or other outside contaminants to enter the tank.

a. There are several types of bushing construction; they are usually distinguished by their voltage ratings, although the classifications do overlap:

Solid (high alumina) ceramic - (up to w5kv)

Porcelain - oil filled (25 to 69kV)

Porcelain - compound (epoxy) filled (25 to 69kV)

Porcelain - synthetic resin bonded paper-filled (34.5 to 115kV)

Porcelain - oil-impregnated paper-filled (above 69kV, but especially above 275kv)

b. For outdoor applications, the distance over the outside surface of the bushing is increased by adding "petticoats" or "watersheds" to increase the creepage distance between the line terminal and the tank.

Contaminants will collect on the surfaces of the bushing and form a conductive path. When this creepage distance is bridged by contaminants, the voltage will flashover between the tank and the conductor. This is the reason why bushings must be kept clean and free of contaminants.

c. Transformer bushings have traditionally been externally clad in porcelain because of its excellent electrical and mechanical qualities (see figure 8-l).

Porcelain insulators are generally oil-filled beyond 35 kV to take advantage of the oil's high dielectric strength. There are a number of newer materials being used for bushings, including: fiberglass, epoxy, synthetic rubbers, teflon, and silica compounds. The manufacturer's instructional literature should be consulted when working with these bushings.

d. Maintenance. Bushings require little maintenance other than an occasional cleaning and checking the connections. Bushings should be inspected for cracks and chips, and if found, should be touched-up with Glyptal paint or a similar type compound. Because bushings are often called on to support a portion of the line cable's weight, it is important to verify that any cracks have not influenced the mechanical strength of the bushing assembly.

e. Testing. Most bushings are provided with a voltage tap to allow for power factor testing of the insulator. If they have no tap, then the power factor test must be performed using the "hot collar" attachment of the test set. The insulation resistance-dielectric absorption test can also be performed between the conductor and the ground connection.

8-3. PRESSURE RELIEF DEVICES

When the transformer is overloaded for extended periods, or when an internal fault occurs, high pressures will occur in the tank. There are a number of devices used to accommodate this pressure change.

a. Pressure relief valves. Pressure relief valves are usually installed behind the pressure gauge on sealed tank units. They are used in conjunction with pressurized nitrogen systems and can be mounted in the gas bottle cabinet or on the tank wall. The bleeder valve is set to bleed-off any pressures that exceed a, preset level (usually around 8-10 psi). This valve is an integral part of the pressurized gas system, and its failure can result in a rupture of the tank.

b. Pressure relief valve testing. The operation of these devices can be checked by manually increasing the tank pressure to the preset level. It is important not to exceed the maximum tank pressure. If the valve does not bleed off the excess pressure, it should be replaced.

c. Mechanical pressure-relief devices. These devices relieve sudden or accumulated internal pressure at a predetermined value. They are usually mounted on the top of the tank, and consist of a diaphragm, a spring-loaded mechanism, and an indicating flag (see figure E-2). When the pressure exceeds a preset level, the diaphragm is raised and the excess pressure is bled off.

The indicating flag remains raised, so that the occurrence will be noted during the next inspection cycle.

Some pressure relief devices are also equipped with contacts that are used to actuate external relays, alarms, or circuit breakers. the space above the tank must be purged with dry nitrogen, and the diaphragm reset any time a relief device is found with its indicating flag popped.

d. Mechanical pressure relief valve testing. A mechanical pressure relief device cannot be tested without removing it from the tank. Since removal is impractical, it should be inspected regularly to ensure there are no cracks in the diaphragm and that the diaphragm/spring mechanism is free to operate. The operation of any relay contact and the associated control wiring

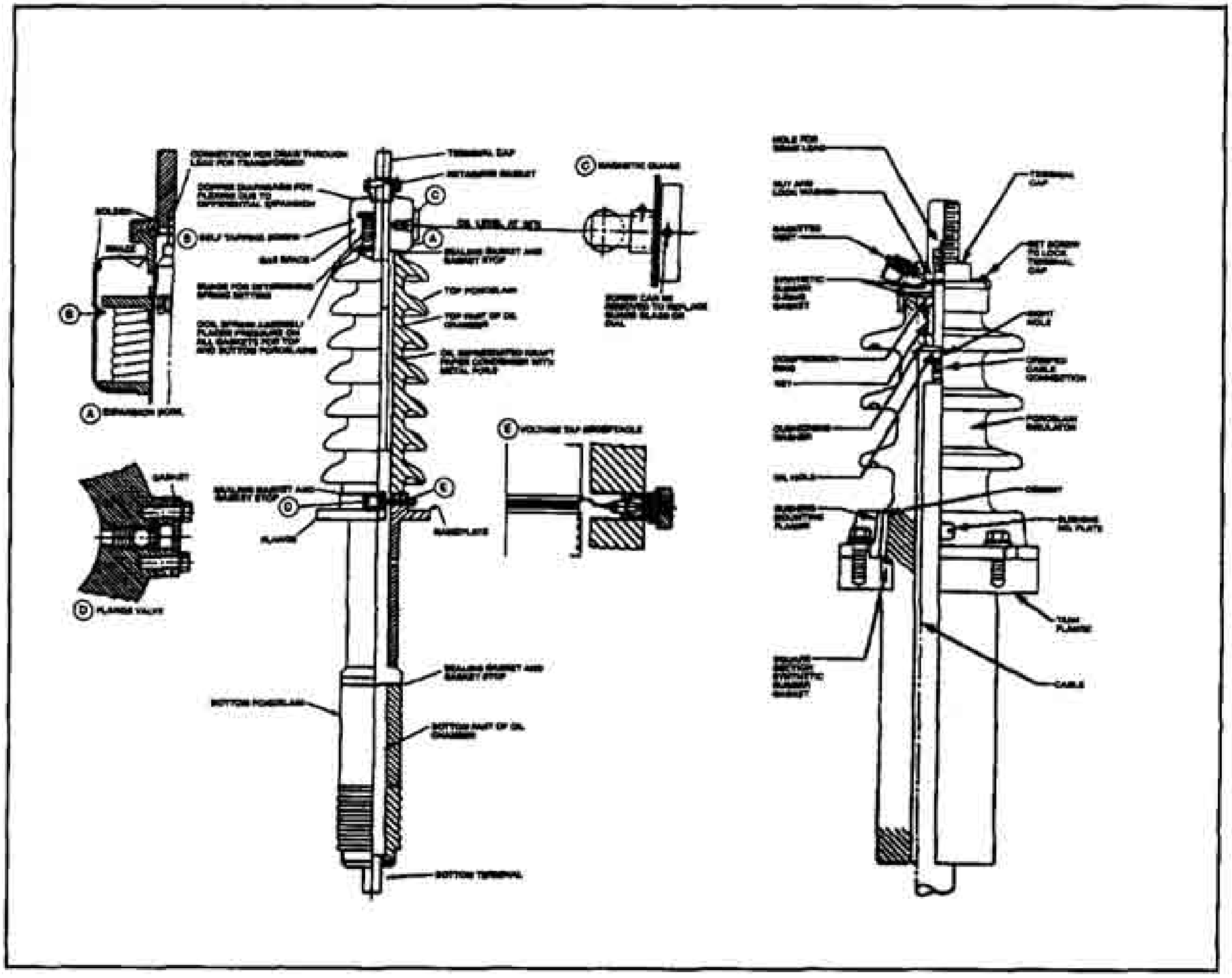


Figure 8-1. Transformer porcelain and oil-filled bushings.

should also be checked periodically,

e. Relief diaphragms. Relief Diaphragms are usually found on conservator-type transformers. Relief diaphragms consist of a bakelite, thin metal, or glass diaphragm mounted on a large pipe that extends above the level of the conservator tank. The diaphragm material is designed to rupture at a predetermined pressure level. Other than inspecting for evidence of rupture, there is little or no maintenance to be performed on these devices. Relief diaphragms must be replaced after rupturing.

f. Sudden pressure relays. These devices consist of a bellows, a small orifice, and a set of relay contacts that are slaved to the mechanical movement of the bellows (see figure 8-3). When the transformer undergoes the pressure changes experienced during normal operation, the small orifice bleeds off the pressure, and the bellows will not move. When an arc or an internal fault occurs, the large volume of gas generated over relatively short time frame pushes on the bellows and actuates the contacts. The contacts are used to actuate an alarm, a circuit breaker, or another relay. There are variations in the design of sudden pressure relays, but they all operate on the same basic principle. Sudden pressure relays are not actuated by any set pressure level; they operate when the rate of change of pressure exceeds a preset value. Because arcing or internal faults generate large quantities of gas over a short period of time sudden pressure relays are effective in detecting fault conditions. Sudden pressure relays provide little protection against overpressure tank conditions occurring over an extended time period.

9. Sudden pressure whe testing. The sudden pressure relay is usually mounted in the gas space above the oil level, and it is important to ensure that oil does not enter the unit. The operation of the relay is verified by checking that the orifice remains open, and that the bellows is free to move. The control wiring and the contact operation should also be verified.

8-4. PRESSURE GAUGES

Most transformers are equipped with a pressure gauge. The gauge assembly consists of a pressure sensitive element (a bulb or a diaphragm), an indicator attached to the element, and a dial calibrated for the required vacuum range of the tank. Although there is little or no maintenance to be performed on a pressure gauge, its operation should be verified if no changes are noted during a number of inspection intervals.

8-5. TEMPERATURE GAUGES

Temperature gauges are either of the "hot spot" or "average tank temperature" type. There are many designs in use. Most average tank temperature gauges consist of a spiral wound bi-metallic element that is directly coupled to a dial-type indicator.

a. Both average reading and hot spot temperature gauges can use a bulk-type detecting unit that is immersed in the oil either near the top of the oil level (see figure 8-4), or near the windings at the spot that is expected to be the hot test. A capillary tube is connected to the bulb and brought out of the tank. The temperature indication is provided either by a linear mark-

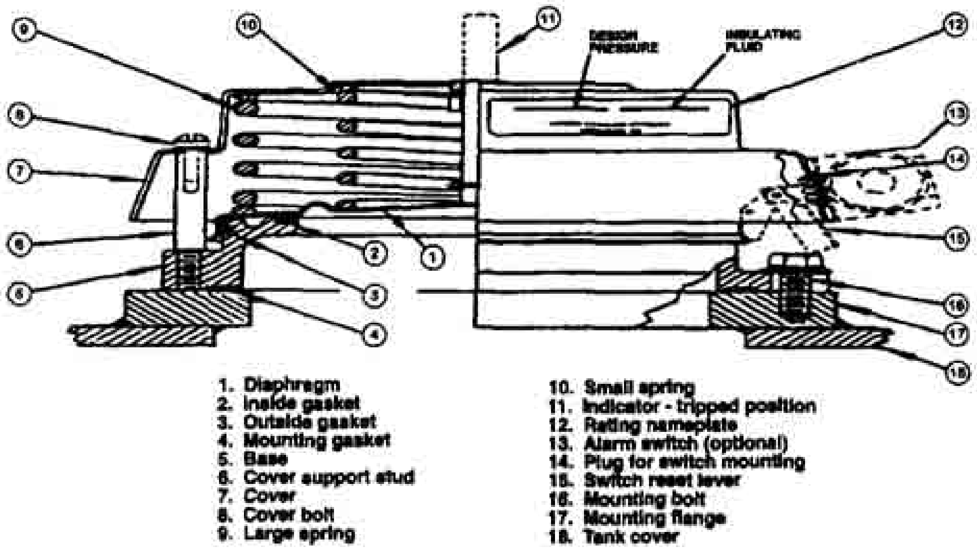


Figure 8-2. Mechanical pressure relief device.

ing on the tube itself, or by a dial-type indicator.

Dial-type gauges can have up to three sets of contacts that will actuate any of the following devices:

(1) The lowest setting usually actuates external cooling fans that will come on at a preset temperature level. The fans will shut off once the temperature has been reduced to the prescribed level.

(2) The contacts can also be set to actuate remote alarms that will alert maintenance personnel of the condition of the transformer. These devices must be reset even though the temperature has returned to normal.

(3) The highest and most critical contact setting on the temperature gauge is connected to a relay or a circuit breaker that will trip out and de-energize the transformer.

b. Most dial-type gauges (see figure 8-5) are equipped with a red indicating needle that has no spring return and will indicate the highest temperature seen since it was last reset. This slaved hand needle reading should be recorded for each inspection interval, and the needle should be reset to ambient temperature so that it will indicate the maximum temperature for the next inspection interval.

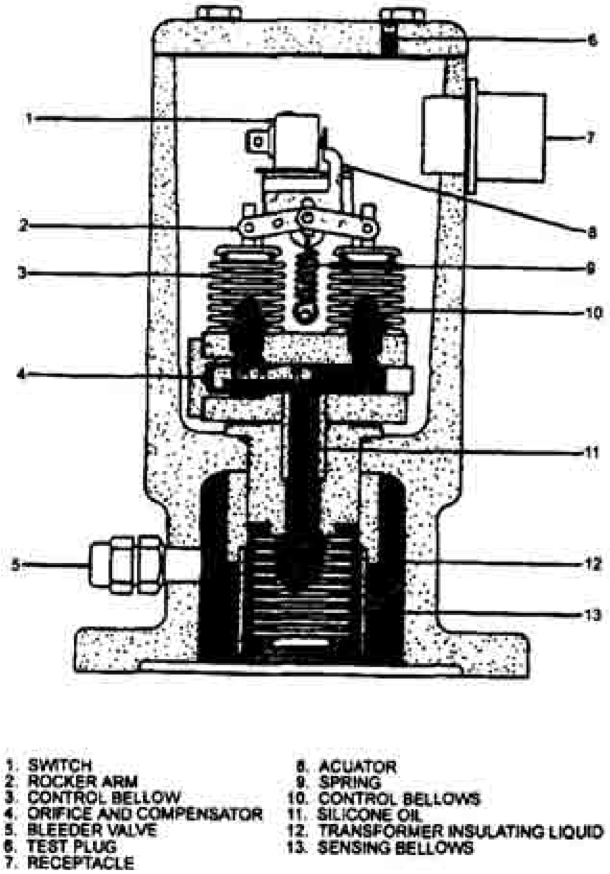


Figure 8-3. Sudden pressure relay.

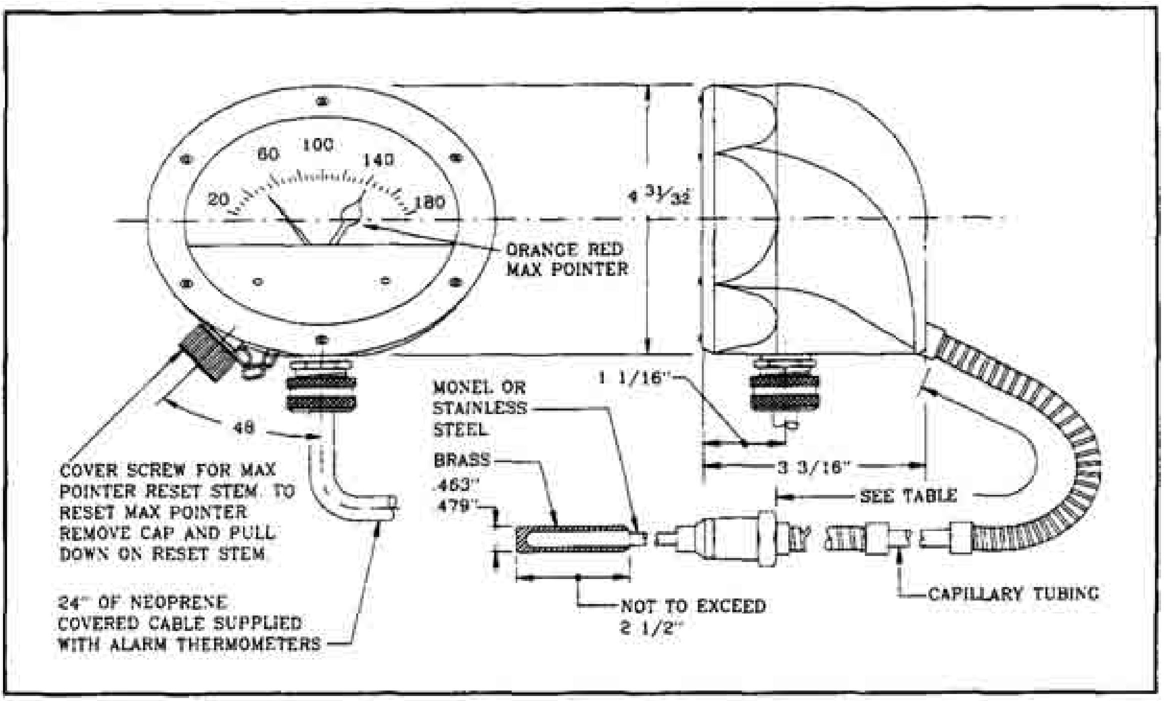
8-6. TAP CHANGERS

As noted in chapter 3, transformers are often required to operate under changing primary voltages, or to provide a number of different secondary voltages. Most transformers are equipped with a tap changer (see figure 8-6), and any number of taps can be brought off of either of the windings to accomplish this voltage change. Tap changers can be conveniently divided into two categories: no-load tap changers and load tap changers.

a. No-load tap changers. No-load tap changing is usually accomplished on the primary side of a step-down power transformer. The taps are usually provided 2-1/2 percent intervals above and below the rated voltage, and the transformer must be de-energized before the tap position can be changed. The taps are changed either by turning a hand wheel, moving a selector switch, or lowering the oil level, opening the manhole, and actually reconnecting the winding leads to various positions on a terminal board. No-load tap changers are usually used to accommodate long-term variations in the primary voltage feed.

b. Load tap changers: Load tap changers are usually located on the secondary side of the transformer. They are used to control the current and voltage as the load is varied. Load tap changing transformers are used especially for furnace applications, and to regulate the changing voltages found in large substations.

(1) Because load tap changers are required to open and close the circuit while it is hot, they incorporate a number of devices to minimize the switching time and the amount of energy (the arc) released. Some tap changers use vacuum bottle type breakers to interrupt the current flow, while others use a conven-



20
60
100
140
180
4 31/32
ORANGE RED MAX POINTER
MONEL OR STAINLESS STEEL
1 1/16"
BRASS
.463"
.479"
48
3 3/16"
SEE TABLE
COVER SCREW FOR MAX POINTER RESET STEM. TO RESET MAX POINTER REMOVE CAP AND PULL DOWN ON RESET STEM
24" OF NEOPRENE COVERED CABLE SUPPLIED WITH ALARM THERMOMETERS
NOT TO EXCEED 2 1/2"
CAPILLARY TUBING

Figure 8-5. Dial Type temperature gauge.

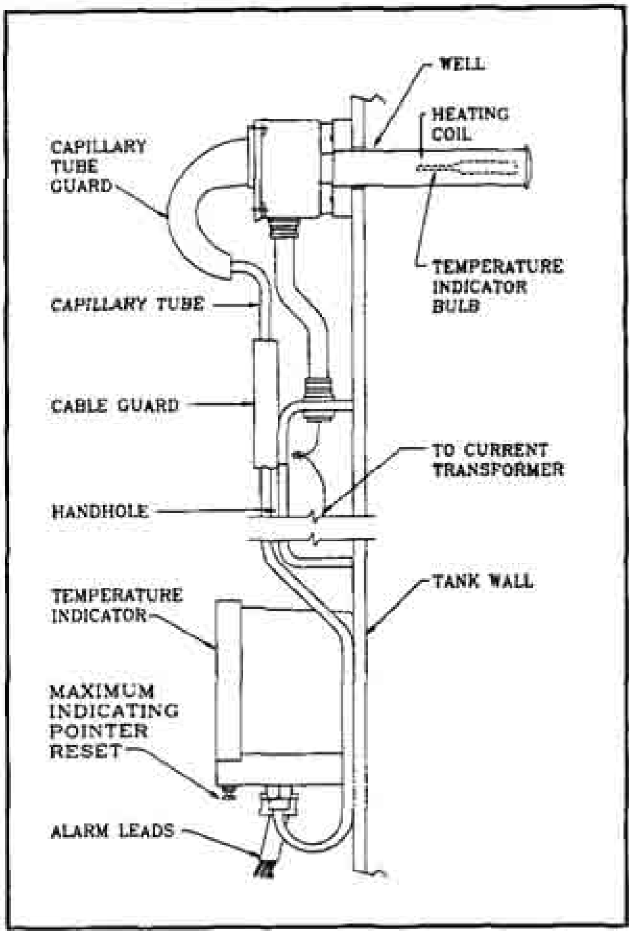


Figure 8-4. Temperature gauge.

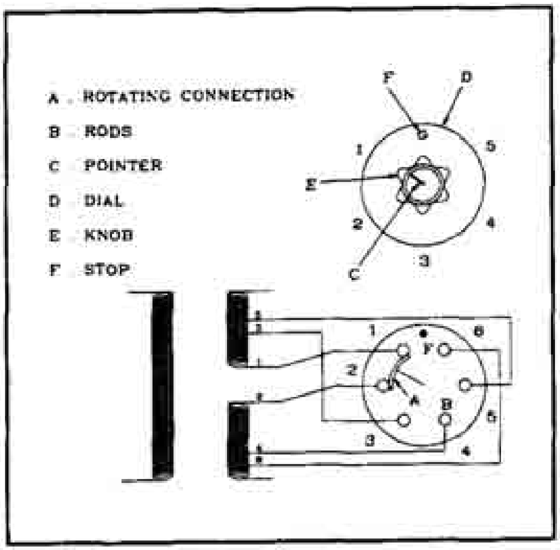


Figure 8-6. Schematic diagram of transformer tap changer.

tional main/arcing contact mechanism, much like that found in a circuit breaker. Other tap changers use resistor or reactor circuitry in the mechanism to limit the current flow at the time the switching occurs. Load tap changers can be either automatic or manual, and can be used to vary the voltage and current by as much as 2 or 3 percent, depending on application.

(2) Most load tap changers are immersed in oil and are contained in a separate compartment from the primary and secondary windings. Because of the large amounts of energy (switching arcs) produced, the oil in the tap changing compartment deteriorates at a much faster rate than the oil in the main compartment.

c. Tap danger testing. The tap changer's operation is verified by performing a turns ratio test at the various tap settings. This holds true for both the no load tap changers. The arcing contact or vacuum bottle assemblies for the load tap changers should be inspected, and the contact resistance should be measured if there is evidence of putting or contact wear. Because of the switching activity, the oil in the tap changer compartment should be sampled and analyzed twice as often as the main tank oil.

8-7. LIGHTNING (SURGE) ARRESTERS

Most transformer installations are subject to surge voltages originating from lightning disturbances, switching operations, or circuit faults. Some of these transient conditions may create abnormally high voltages from turn to turn, winding to winding, and from winding to ground. The lightning arrester is designed and positioned so as to intercept and reduce the surge voltage before it reaches the electrical system.

a. Construction. Lightning arresters are similar to big voltage bushings in both appearance and construction.

They use a porcelain exterior shell to provide insulation and mechanical strength, and they use a dielectric filler material (oil, epoxy, or other materials) to increase the dielectric strength (see Figure 8-7).

Lightning arresters, however, are called on to insulate normal operating voltages, and to conduct high level surges to ground. In its simplest form, a lightning arrester is nothing more than a controlled gap across which normal operating voltages cannot jump. When the voltage exceeds a predetermined level, it will be directed to ground, away from the various components (including the transformer) of the circuit. There are many variations to this construction. Some arresters use a series of capacitances to achieve a controlled resistance value, while other types use a dielectric element to act as a valve material that will throttle the surge current and divert it to ground.

b. Maintenance. Lightning arresters use petticoats to increase the creepage distances across the outer surface to ground. Lightning arresters should be kept clean to prevent surface contaminants from forming a flashover path. Lightning arresters have a metallic connection on the top and bottom. The connectors should be kept free of corrosion.

c. Testing. Lightning arresters are sometimes constructed by stacking a series of the capacitive/dielectric elements to achieve the desired voltage rating. Power factor testing is usually conducted across each of the individual elements and, much like the power factor test on the transformer's windings, a ratio is computed between the real and apparent current values to determine the power factor. A standard insulation resistance-dielectric absorption test can also be performed on the lightning arrester between the line connection and ground.

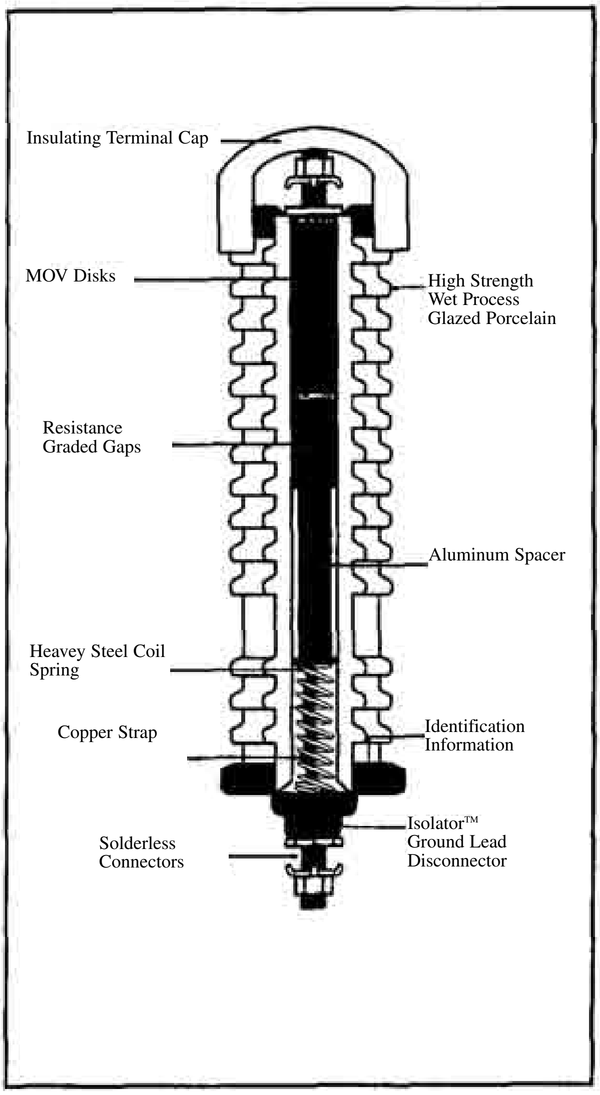


Figure 8-7. Lightning arresters.

CHAPTER 9
COMPREHENSIVE MAINTENANCE/TESTING PROGRAM

9-L. TRANSFORMER MAINTENANCE

Of all the equipment involved in a facility's electrical distribution system, the transformer is probably the most neglected. A transformer has no moving parts; consequently it is often considered maintenance-free.

Because the transformer does not trip or blow when oven-stressed (except under extreme conditions), it is frequently overloaded and allowed to operate well beyond its capacity. Because the transformer is usually the first piece of equipment on the owner's side of the utility feed, it usually operates at much higher voltages than elsewhere in the facility and personnel are not anxious to work on or around it. The fact that a transformer has continued to operate without the benefit of a preventive maintenance/testing program says much about the ruggedness of its construction. However, a transformer's ruggedness is no excuse not to perform the necessary testing and maintenance.

a. Any piece of electrical equipment begins to deteriorate as soon as it is installed. The determining factor in the service life of a transformer is the life of its insulation system. A program of scheduled maintenance and testing will only extend the life of the transformer, but can also provide indications of when a transformer is near the end of its service life, thus allowing for provisions to be made before an unplanned failure occurs. Also, a transformer checked before a failure actually occurs can usually be reconditioned or refurbished more easily than if it had failed while on line.

b. There are many benefits to a comprehensive maintenance and testing program

(1) Safety is increased because deficiencies are noted and corrected before they present a hazard.

(2) Equipment efficiency is increased because conditions that ultimately increase the transformer's losses can be corrected.

(3) If a problem occurs, it can usually be rectified more quickly because service records and equipment information are centrally located and readily available.

(4) As the power requirements of a facility grow, any overloaded or unbalanced circuits will be detected more quickly, allowing for adjustments to be made before any damage is incurred.

(5) lf impending failures are discovered, the repair work can be scheduled during off-peak hours, reducing the amount of inconvenience and expense.

c. To realize these benefits, a comprehensive plan must be thoughtfully developed and diligently administered.

Although the generalized needs of transformers are addressed here, depending on construction and application, transformers may need more, or less, frequent attention than specified here. Once again, these are simply guidelines, and in no instance should the manufacturer's recommendations be neglected.

9-2. MAINTENANCE AND TESTING PROGRAM

A comprehensive maintenance and testing program is instituted for a number of reasons and benefits. The objective of a comprehensive program is not just to get the work done, but to ensure that the work is completed according to a methodical and priority-oriented plan of action. A comprehensive program ensures that all maintenance needs are fulfilled, and that testing and inspections are performed to verify that the equipment Is not deteriorating at an accelerated rate. By documenting all activities and performing the work as part of an overall plan, the program also helps to eliminate any redundancies or duplication efforts. There are five basic activities involved In a comprehensive program:

a. Inspections. Inspections do not require an outage, and can therefore be performed more frequently than most other maintenance functions. Inspections are a very effective and convenient maintenance tool. If inspections are carefully performed along with an oil analysis, they can reveal many potential problems before damage occurs. A transformer inspection should include all gauge and counter readings, the operating conditions of the transformer at the time of the inspection, a check of all auxiliary equipment, the physical condition of the tank, and any other visible factors that affect the operation of the transformer.

Inspections should be conducted on a weekly basis, and should be thoroughly documented and stored with the transformer's service records.

b. Infrared (IR) Imaging. Infrared Imaging is also an effective inspection tool. Loose connections, unbalanced loads, and faulty wiring will all emit relatively higher levels of heat than their surroundings. Infrared imaging systems provide a screen display (like a TV) that shows the temperature difference of the items on the screen. It is the relative difference in temperature, and not the actual temperature that will indicate any problems. If the IR scan is performed annually, it should be performed 6 months after the annual maintenance outage, to maximize protection between the hands-on service intervals.

c. Sampling. Drawing samples of the transformer's fluid provides the opportunity to actually remove a portion of the transformer's insulation and subject it to a battery of standardized tests, under controlled laboratory conditions, with the benefit of complex laboratory equipment. Most transformers can be sampled while energized, so there is no major inconvenience involved.

Although samples should be taken more frequently at the outset of a program (every 6 months), once the baseline data and the rate of deterioration have been determined, the frequency can usually be adjusted according to the needs of the transformer (normally once a year).

d. Maintenance. Most maintenance functions require an outage since they present a hazard to the personnel involved. Maintenance functions involve periodic actions that are performed as a result of the expected wear and tear and deterioration of the transformer. They include wiping down all bushings and external surfaces, topping off fluids, tightening connections, reconditioning deteriorated oil, recharging gas blankets and checking gas bottles, touching-up the paint, fixing minor leaks, and doing any maintenance required for fan systems and tap changer systems. Most of these operations should be performed annually, when the transformer is de-energized for testing.

e. Testing. Testing provides functional verification of the condition of the transformer. All transformer testing requires an outage. The tests that should be performed on a regularly scheduled basis are: Power factor, insulation resistance-dielectric absorption, Turns ratio and winding resistance. Testing is an important part of a comprehensive program because it uses electricity to verify the operating condition of the transformer.

Most outdoor transformers should be tested annually, although lightly loaded transformers in favorable environments can get by with testing every 3 years. More frequent testing should be performed at the outset of a program to determine the specific transformer's needs.

f. Repair. Although there is little distinction between maintenance and repair activities, the planned or unplanned nature of the work will usually determine its category. The whole idea of the comprehensive program is to minimize the amount of unplanned downtime necessary for repairs. When the deterioration of the transformer oil is monitored, and arrangements are made to recondition the oil during a planned outage, it can be called a maintenance function. When a transformer fault occurs, and subsequent testing reveals that the oil is unfit for service, the unplanned oil reconditioning becomes a repair function; in this case, there is a much more significant inconvenience factor.

9-3. DOCUMENTATION

Performing the work on the transformer is all well and good, but the information gained is practically useless if it cannot be easily accessed and compared to other test results. To ensure that all inspection, test, analysis, maintenance, and repair data can be used most effectively, the data must be properly documented and readily accessible. This usually involves keeping records of all activities in a centralized filing system.

a. Although the technician performing the work is ultimately responsible for getting the information on paper, a properly constructed record will not only help the technician, but will also help the personnel responsible for organizing and storing the data. Every record, whether it is an inspection, test, or repair record should have as much information about the transformer and the test conditions as possible. This includes the manufacturer, the kVA rating, the serial number, and the voltage ratings. There should also be space on the record to note the temperature, humidity, and weather conditions at the time of the activity. Another factor that can be extremely important is the loading conditions immediately prior to (for de-energized activities) or during (for inspections or sampling) the service procedure.

All of this information can be extremely helpful for interpreting the results.

b. Several factors should be taken into consideration when devising a maintenance program for a specific transformer. The two most important factors are the environment in which the transformer is operating and the load to which it is being subjected. Although the exact effect these conditions will have on the transformer may not be known at the outset, the rate of deterioration should be determined by the end of the first year of the program and any adjustment can be made after that.

9-4 SCHEDULING

It is very easy to prescribe maintenance and testing, and most facilities management personnel will agree to the benefits of the program. It is when the outage must be obtained to perform the work that the problems arise. This is where the comprehensive part of the program comes into play. It is the responsibility of the maintenance department to work with all the departments involved to schedule the necessary outages.

a. Once all involved parties have decided to institute a preventive maintenance and testing program, the maintenance needs of the transformer and the availability of the outages necessary to perform the work must be considered. Because the power transformer usually affects a large portion of the electrical service to a facility, scheduling outages can be extremely difficult.

Quite often, the work must be performed at night or during off-peak hours over the weekend. Although this can sometimes cause major inconveniences, the work must be performed, and the biggest help the maintenance personnel/department can provide is to minimize the time required for the outage.

b. Except for visual inspections, infrared (IR) inspections and sampling, all transformer maintenance/testing procedures require an outage. Unless there are redundant systems such as generators and alternate feeds, the outage will black out portions of the facility.

It is important that all equipment be assembled and preparations be made before the switch is thrown. This includes having all the necessary test equipment and spare parts on hand. Although it may be difficult to estimate the amount of time each service procedure will require, as the program is implemented, these factors will be easier to estimate, and they will be performed more quickly as the maintenance personnel become more experienced.

c. The transformer should be inspected on a weekly basis. This inspection should be thoroughly documented, and should include all gauge readings, load currents, and the visual condition of all the transformer's auxiliary equipment. If unexplained maximum temperatures occur or if there is an accelerated deterioration, daily inspections, or the use of load recording instrumental should be considered. Infrared scanning can also be performed without an outage. The IR scan should be performed every 6 or 12 months, depending on the transformer type and application.

d. The transformer's insulating fluid should be sampled every 6 months during the first year of the program and annually for the remainder of its service life.

If problems are noted, or if the oil begins to deteriorate at an accelerated pace, the transformer should be sampled more frequently. Tap changers and auxiliary switching compartments should also be sampled more frequently. The information for each sampling interval should be transcribed onto a record that will allow easy trending analysis. If an outside contractor is called in to perform the sampling and analysis, the record should include the sample information shown, especially the atmospheric conditions at the time of the test.

e. The comprehensive maintenance and testing program will be most effective if the various electrical tests are coordinated by a central department. The testing and maintenance of equipment other than transformers in the facility's electrical distribution system should be integrated into an overall program. By centralizing the maintenance activities for all of the facility's electrical equipment, other items in each individual circuit can be investigated to help explain any problems being experienced on a specific piece of equipment.

Centralizing the various inspection/test/repair records also promotes the development of trending data, and the analysis of test data over a number of test intervals. This centralized filing system should also be used to generate schedules and to plan activities. If possible, a computerized system should be used to generate schedules and to plan activities. If possible, a computerized system should be established to indicate when the items in the system are due for service.

CHAPTER 10

STATUS OF TRANSFORMER MONITORING AND DIAGNOSTICS

10-1. INTRODUCTION

As a key component of all AC power systems, a properly functioning power transformer is essential for maintenance system integrity. Consequently, new and improved monitoring and diagnostic techniques continue to be developed to minimize unplanned system outages and costly repairs.

10-2. TRANSFORMER MONITORING

For the purposes of this section, monitoring refers to online measurement techniques, where the emphasis is on collecting pertinent data on transformer integrity and not on interpretation of data. Transformer monitoring techniques vary with respect to the sensor used, transformer parameters measured, and measurement techniques applied. Since monitoring equipment is usually permanently mounted on a transformer, it must also be reliable and inexpensive.

a. To minimize costs, it is important to minimize the number of measurements taken. It is therefore necessary to identify parameters that are most indicative of transformer condition. Consequently, selection of these parameters must be based on failure statistics, as shown in figure 10-1. The pie chart shows typical failure distribution of transformers with on-load tap changers (OLTC). As indicated, winding and OLTC failures dominate; consequently, the focus of most monitoring techniques is to collect data from parameters that can be used to assess the condition of winding and tap changers. Dissolved gases in oil and partial discharges (PD) are common parameters monitored related to winding and insulation condition. Temperature and vibration monitoring are commonly used for assessing OLTC condition.

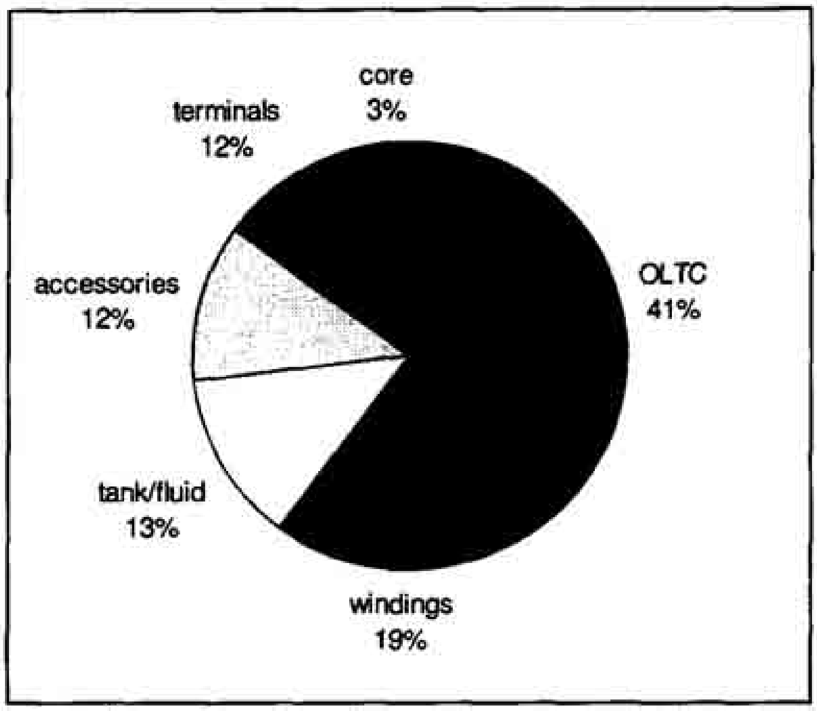


Figure 10-1. Typical failure distribution for substation transformers.

b. Dissolved Gases in oil: As mentioned in paragraph 5-3 dissolved gas-in-oil analysis is an effective diagnostic tool for determining problems in transformer operation. However, this analysis is typically performed off-post, where sophisticated (and usually expensive), equipment is used to determine gas content. To reduce the risk of missing incipient faults due to long sampling intervals, monitoring techniques are being developed to provide warnings with respect to changes in gas types and concentrations observed within a transformer. Conventional dissolved gas-in-oil analysis is performed after a warning is issued. Several transformer gases and corresponding sources are listed in Table 10-l.

c. The main challenges to on-line gas monitoring are not only to develop accurate and low cost sensors, but sensors that are versatile enough to detect the presence of multiple gases. Several new sensor technologies are now commercially available to measure concentration changes of multiple gases, and many more are in development. The HYDRAN technology for example, by Syprotec Inc. (Montreal, Quebec), uses a selectively permeable membrane and a miniature electrochemical gas detector to measure the presence of hydrogen, carbon monoxide, ethylene and acetylene dissolved in oil. The chemical reactions, which result when these gases permeate through the membrane and mix with oxygen, generate electrical current that is measured as a voltage drop across a load resistor. This voltage drop is used to determine a composite parts-per-million value of the four gases. This technology is used to detect change in gas concentrations only. If change is detected, an alarm is triggered, which indicates that an oil sample should be taken from the transformer and analyzed to evaluate the nature and severity of the fault. The Transformer Gas Analyzer, developed by Micromonitors, is also designed to detect hydrogen, carbon monoxide, ethylene, and acetylene in mineral oil-filled transformers. The instrument operates on a real-time basis with sensors immersed directly in the oil inside the transformer, and is based on metal insulator semiconductor technology. The AMS-500 PLUS, by Morgan Shaffer Company, measures both dissolved hydrogen and water continuously, on-line. Asea Brown Boveri is developing sensors based on metal oxide technology; however, these sensors are still in the field prototype stage.

(1) Partial Discharges: The most common method for on-line detection of partial discharges (PD) is the use of acoustical sensors mounted external to the transformer. One example of a commercially available acoustic emission monitoring instrument is the Corona 500, by NDT International, Inc., which is designed to detect partial discharge of electrical transformers while on-lie. The main difficulty with using acoustical sensors in the field, however, is in distinguishing between internal transformer PD and external PD sources, such as discharges from surrounding power equipment. An alternative method has been proposed recently to differentiate between internal and external PD, and is based on the combined use of signals from a capacitive tap and signals from an inductive coil fitted around the base of the bushing. A warning signal is provided if PD activity develops inside the tank; therefore, this technique does not indicate the seriousness of the internal defect.

(2) Temperature. The load capability of a transformer is determined by the maximum allowable hot spot temperature of the winding. Hot spot values are usually calculated from measurements of oil temperatures and load current. A more expensive technique is to use distributive fiber optic temperature sensory.

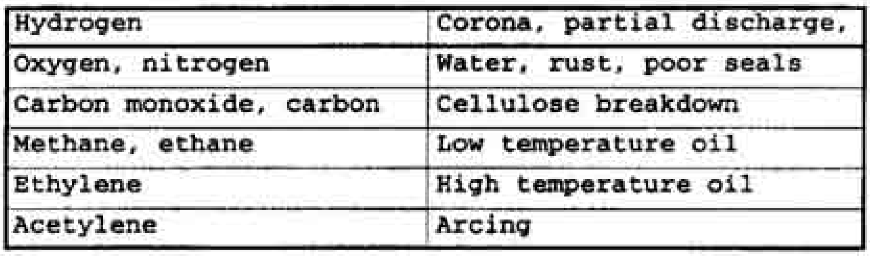
Since tap changer condition is a key transformer component, another method consists of metering and monitoring the differential temperature between the main tank and tap changer compartment. This method can be used for detecting coking of contacts. For example, the Barrington TDM-ZL, by Barrington Consultants (Santa Rosa, CA), measures oil temperature in the tap changer compartment and in the main tank. This technology is designed to interface with a SCADA system and also provides local digital indication for main tank, OLTC, differential, peak and valley oil temperatures.

(3) Vibration: Vibration monitoring has also been proposed for detecting mechanical and electrical faults in the OLTC compartments. The method is still under development, but could prove to be an effective technique for detecting OLTC mechanical problems such as failing bearings, springs, and drive mechanisms, as well as deteriorating electrical contracts.

(4) Other Methods: Recently, there has been a considerable amount of research effort focused on improving the intelligence of transformer monitoring systems.

The approach is to compare the results of actual measurements for example, using the sensors mentioned above, with predictions obtained through simulation models. Model parameters are determined to best fit past transformer measurements. For normal transformer operation, simulation results should match the results obtained from actual measurements. However, measurements deviating from predictions may indicate a problem with the transformer. The claim is that this technique can provide very sensitive measures of transformer performance. For example, the Massachusetts Institute of Technology uses adaptive mathematical models of transformer subcomponents that tone themselves to each transformer using parameter estimation.

They have used the model-based approach for accurate on-line prediction of top oil temperature, which has been verified using data from a large transformer in service. Of course, other performance predictions can be made using appropriate measurable quantities such as dissolved gas content.



Hydrogen	Corona, partial discharge,
Oxygen, nitrogen	Water, rust, poor seals
Carbon monoxide, carbon	Cellulose breakdown
Methane, ethane	Low temperature oil
Ethylene	High temperature oil
Acetylene	Arcing

Table 10-1. Transformer gases and corresponding sources.

10-3. TRANSFORMER DIAGNOSTICS

For the purposes of this section, diagnostics refers to the interpretation of data and measurements that are performed offline. Diagnostics are used as a response to warning signals and to determine the actual condition of a transformer. Since it is not a permanent part of a transformer, diagnostic equipment is typically much more sophisticated and expensive than monitoring equipment.

a. Dissolved gas-in-oil analysis is the most common method for incipient fault detection. This section will focus on discussing the results of two research efforts including: (1) an expert system approach based on dissolved gas analysis, and (2) an artificial neural network approach to detect incipient faults.

b. Expert System Approach. The analysis of the mixture of faulty gases dissolved in transformer mineral oil has been recognized for many years as an effective method for the detection of incipient faults. Experts from industry, academia, and electric utilities have reported worldwide on their experiences, and have developed criteria on the basis of dissolved gas analysis (DGA). The objective of one expert system approach is to develop a rule-based expert system to perform transformer diagnosis similar to a human expert. Results from a prototype expert system based on DGA has been published. The main difficulty to be overcome is transforming qualitative human judgments into quantitative expressions. The prototype expert system uses fuzzy-set models to facilitate this transformation.

In short, the fuzzy-set model is used for representing decision roles using vague quantities. For example, the prototype system uses a fuzzy set to manage three diagnostic uncertainties, including: norms, gas ratio boundaries, and key gas analysis. Results from the prototype study indicate that an expert system could be a useful tool to assist maintenance personnel.

c. Artificial Neural Network Approach: With a similar focus as the expert system and fuzzy-set approach, researchers are also wing artificial neural networks (ANN) to reveal some of the hidden relationships in transformer fault diagnosis. Very complex systems can be characterized with minimal explicit knowledge using ANNs. The relationship between gas composition and incipient-fault condition is learned by the ANN from actual experience. The aim of using ANN is to achieve better diagnosis performance by detecting relationships that are not apparent (that is, relationships that might otherwise go unnoticed by the human eye).

For example, cellulose breakdown is a source of carbon monoxide; however, overheating, corona and arcing all cause this type of breakdown. The primary difficulty is in identifying and acquiring the data necessary for properly training an ANN to recognize certain complex relationships. The more complex a relationship is, the more training data are needed. The study presented in the Zhang, Ding, Liu, Griffin reference used five gases as input features including, hydrogen, methane, ethane, ethylene, and acetylene. The results of the study look promising, and indicate that the reliability of the ANN approach might be improved by incorporating DGA trend data into ANN training, such as increasing rates of gas generation.

10-4. CONCLUSIONS

Several new on-line monitoring technologies are now commercially available, and more are in development.

Research is being conducted that is focused on providing on-line diagnostic capability using model-based techniques. A trend toward developing more accurate and effective incipient fault diagnostics, based on past experience with dissolved gas-in-oil analyses, is evident from the recent development of expert systems and artificial neural networks. As sensor technology and interpretation skills mature, it is likely than a shift will be made toward performing on-line diagnostics.

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